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NATIONAL PUBLIC HEARINGS ON POWER PLANT COMPLIANCE WITH SULFUR OXIDE AIR POLLUTION REGULATIONS

ENVIRONMENTAL PROTECTION AGENCY

JANUARY 1974

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Report of the
Hearing Panel

National Public Hearings on Power Plant Compliance with Sulfur Oxide Air Pollution Regulations

January 1974

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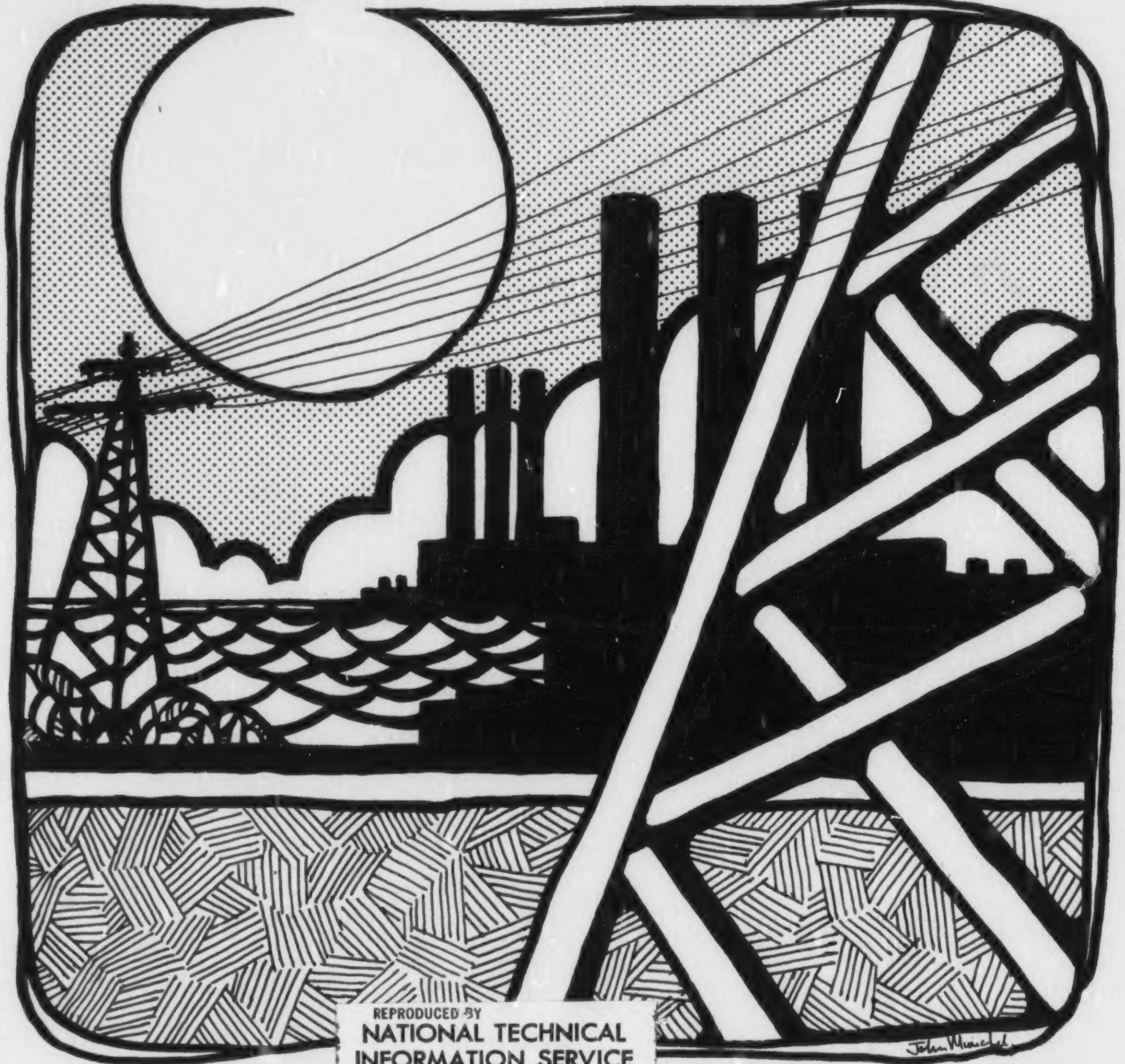

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF THE
ADMINISTRATOR

January 22, 1974

Honorable Russell E. Train
Administrator
U. S. Environmental Protection Agency
401 M Street, S.W.
Washington, D. C. 20460

Dear Mr. Train:

From October 18 to November 2, 1973, the Environmental Protection Agency held a special public hearing in the Washington, D. C. area to review the status of power plant compliance with sulfur oxide (SO_x) air pollution emission limitations. This hearing was called because power plants are the largest source of SO_x emissions in the U.S., because large numbers of power plants are not yet in compliance with SO_x emission limitations, and because, in most cases, only 1 1/2 years remain under the established implementation plans for these plants to achieve compliance.

The attached report represents the consensus of the EPA officials who comprised the hearing panel and presents our findings and recommendations. Principal among these findings are the following:

- Flue gas desulfurization (FGD) technology must be installed on large numbers of power plants if SO_x emission requirements adopted pursuant to the Clean Air Act are to be met in the 1970's. Supplies of low-sulfur fuels are now and will continue to be inadequate to provide the sole means of complying with SO_x emission limitations.
- Many established SO_x emission limitations will not be met by the mid-1975 compliance date of most State implementation plans and will not be met at all unless the electric utility industry makes the necessary commitments to install FGD systems where needed.
- With several noteworthy exceptions, the electric utility industry has not aggressively sought out solutions to the problems they argue exist with FGD technology.

- Although most utility witnesses testified that FGD technology was unreliable, that it created difficult sludge disposal problems, and that it cost too much, the hearing panel finds, on the basis of utility and FGD vendor testimony, that the alleged problems can be, and have been, solved at a reasonable cost. The reliability of both throwaway-product and saleable-product FGD systems has been sufficiently demonstrated on full scale units to warrant widespread commitments to FGD systems for SO_x control at coal- and oil-fired power plants.

- The utility industry has generally lacked a real incentive to develop FGD technology and to install this technology where needed to meet SO_x emission requirements.

These findings are based on oral and written testimony received during the hearing. Witnesses included some 20 utilities, 5 trade associations, 8 State agencies, 11 vendors of pollution control equipment, and 5 environmental or public interest groups. A full transcript of the testimony at this hearing is available to the public in EPA's Public Affairs Office, 401 M Street, S.W., Washington, D. C.

EPA officials forming the principal hearing panel were Dr. Robert Sansom, Assistant Administrator for Air and Water Programs; Dr. John Burchard, Director of the Control Systems Laboratory; Dr. Bernard Steigerwald, Director of the Office of Air Quality Planning and Standards; Mr. Richard Wilson, Director of the Division of Stationary Source Enforcement; and myself. Representatives from EPA regional offices also participated on the panel during portions of the hearing.

The hearing panel recommends that the electric utility industry make immediate commitments to install FGD systems where needed to meet SO_x emission requirements and that EPA and the States create an incentive for this commitment by establishing expeditious but reasonable compliance schedules and by vigorously enforcing these schedules.

Respectfully submitted,

John Quarles

John R. Quarles, Jr.
Chairman of the Hearing Panel
Deputy Administrator, EPA

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Report of the Hearing Panel

National Public Hearings
on
Power Plant Compliance
with
Sulfur Oxide Air Pollution Regulations

Conducted
October 18, 1973 through November 2, 1973
by the
United States Environmental Protection Agency

Submitted to the Administrator
U.S. Environmental Protection Agency
by the
Members of the Hearing Panel

January 1974

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1. Summary and Recommendations

Background

Excess quantities of sulfur oxides (SO_x) seriously affect human health through increased incidences of respiratory disease and damage many types of materials. Congress amended the Clean Air Act in 1970 to establish strict requirements and timetables to clean the air. Where health-related standards were involved, cost and difficulty of control were not to be issues in establishing the standards or the compliance schedules to meet them.

As required by the Act, EPA promulgated primary (health-related) and secondary (welfare-related) ambient air quality standards in April 1971 for a number of air pollutants, including sulfur oxides. By mid-1972 the States had adopted and EPA had approved implementation plans that established emission requirements for most sources that needed to be controlled to meet the ambient air quality standards. Power plants emitted over 17 million tons or nearly 60 percent of the total SO_x in 1972 and were therefore included among the sources needing control.

The Act required that emission limitations related to attainment of primary standards be met as quickly as possible, and no later than mid-1975. However, where strict criteria were met, limited extensions were provided by the statute. Congress intended that achievement of primary ambient air quality standards receive priority over achievement of more stringent requirements. EPA has urged that States review their implementation plans to assure that they adequately reflect this priority.

There are about 970 fossil-fueled power plants in the U. S. today having a combined generating capacity of about 302,000 megawatts. Of this capacity, roughly 55 percent (166,000 megawatts) are coal-fired, 17 percent (51,000 megawatts) are oil-fired, and 28 percent (85,000 megawatts) are gas-fired. All gas-fired plants are obviously now in compliance with sulfur oxide emission requirements. Some of the coal- and oil-fired plants were in compliance with sulfur oxide emission requirements when the requirements were adopted and many other plants have been or are now being brought into compliance by converting to fuels having lower sulfur contents.

Switching to a low-sulfur fuel would seem to be the simplest route to compliance with SO_x emission requirements. Coal washing and/or limited blending of present fuels with lower sulfur fuels is often sufficient, and in such cases, total conversion to a lower sulfur fuel would not be required. However, supplies of low-sulfur fuels are limited and will not be sufficient to permit all noncomplying power plants to meet the emission requirements. Furthermore, use of low-sulfur western coal by plants east of the Mississippi River would result in a failure to use readily available high-sulfur eastern coal during a fuel supply crisis. The energy crisis will aggravate the existing shortage of low-sulfur fuels. Since supplies of low-sulfur fuels will be insufficient, flue gas desulfurization (FGD) systems will be required on a large number of power plants in order to achieve compliance with SO_x emission limitations. Use of FGD systems will enable power plants to meet emission requirements while using important high-sulfur fuel resources.

Many utilities have suggested that, rather than meet existing SO_x emission requirements, they be allowed to use tall stacks and intermittent control systems to achieve ambient air quality standards. Such techniques rely upon the dispersion of pollutants instead of the constant reduction of pollutant emissions. EPA considers constant emission reduction techniques, such as FGD, far superior to dispersion techniques and has proposed regulations that limit the use of such dispersion techniques to situations where constant emission reduction controls are not available. Dispersion techniques can, however, often be appropriately required as interim steps (to minimize the impact of plant operation on air quality) in schedules requiring compliance with emission limitations.

It is difficult to estimate the magnitude of the need for FGD systems since this need depends on the present and future availability of low-sulfur coal and oil, the number of oil-fired plants that will switch to coal, and the extent to which supplies of low-sulfur fuels can be redistributed to areas where they are most needed. EPA's best current estimate of the need through 1980 for FGD systems to allow coal-fired power plants to meet primary ambient air quality standards and new source performance standards is that some 90,000 megawatts of FGD control will be necessary. This represents an application of FGD control to about 30 percent of the total projected national coal-fired generating capacity in 1980. Additional long range FGD requirements will, of course, include systems for oil-fired plants, systems for plants to meet State emission limitations designed to improve and maintain air quality below primary standards, and systems for other sources such as large industrial boilers.

This report assesses the oral and written testimony received during the public hearing on the status of power plant compliance. Witnesses included representatives of some 20 utilities, 5 trade associations, 8 State agencies, 11 vendors of pollution control equipment, and 5 environmental or public interest groups. These witnesses are listed by affiliation in Appendix C. Principal findings and recommendations are summarized below.

Findings

1. Flue gas desulfurization (FGD) technology must be installed on a large number of power plants if sulfur oxide (SO_x) emission requirements adopted purusant to the Clean Air Act are to be met in the 1970's.

(a) there was general agreement from witnesses at the hearing that low-sulfur fuel supplies are now and will continue to be inadequate to provide the sole means of complying with SO_x emission limitations.

(b) witnesses generally agreed that technologies such as coal gasification and liquefaction to take sulfur from coal will not be available until the 1980's and that therefore FGD represents the only technology that will be available within the next several years to control SO_x.

(c) witnesses generally agreed that FGD systems, when operating properly, can reduce SO_x emissions by 85 to 90% (sufficient to meet most, if not all, emission requirements).

(d) the continued use of available high-sulfur coal combined with FGD control is especially important given our present energy crisis.

2. Many established SO_x emission limitations will not be met by the mid-1975 compliance date of most State implementation plans and will not be met at all unless the electric utility industry makes the necessary commitments to install FGD systems where needed.

   (a) only a few utility witnesses testified that their companies have compliance programs to install FGD systems at plants for which low-sulfur fuels will not be available. To date only 44 FGD units controlling about 18,000 megawatts of generating capacity have been installed or committed to by utilities in the U. S.

   (b) while the time required to design and install an FGD system on an existing plant varies with the size and retrofit characteristics of the plant, testimony at the hearing suggested that typical design and installation times will run from 27 to 36 months. This time requirement is obviously longer than the 18 months left before the mid-1975 compliance date of most State Implementation Plans. For those installations where a modular approach is warranted, typical design and installation times will run from 41 to 54 months.

(c) a number of witnesses testified to the capacity of vendors of FGD systems to provide these systems. While it is clear that vendor capacity now exceeds orders for FGD systems, it is also clear that excess capacity is not now as great as the need for FGD systems; hence, vendor capacity will tend to constrain the speed at which systems can be installed.

3. With several noteworthy exceptions, the electric utility industry has not aggressively sought out solutions to the problems they argue exist with FGD technology.

    (a) while a few utilities, generally the smaller ones, testified that they had aggressive programs to solve alleged problems with FGD technology, most utilities seem content to raise the problems and wait for other utilities to solve them. Only 22 of the some 300 utilities operating fossil-fueled plants in this country have installed or have made a commitment to install at least one full scale FGD system.

    (b) utility industry research and development efforts in general are limited and in 1972 amounted to less than 1 percent of industry revenues. Work on FGD technology is only a small but undetermined portion of this effort.

    (c) the testimony of some utilities indicates that they have applied greater efforts to defending their lack of progress or to attempting to change existing emission requirements than they have in controlling their SO_x emission through FGD technology.

    (d) while testimony at the hearing indicated that the control of the chemistry of FGD systems is critical to reliable operation, few utilities testified that they have hired personnel skilled in such chemical operations.

    (e) testimony from several utilities indicated that they are not aggressively following the work of those companies in the U. S. and Japan that have installed full scale FGD systems. This lack of active monitoring makes a 'wait and see' attitude less defensible.

4. Although most utility witnesses testified that FGD technology was unreliable, that it created difficult sludge disposal problems, and that it cost too much, the hearing panel finds,

on the basis of utility and FGD vendor testimony, that the alleged problems can be, and have been, solved at a reasonable cost. The reliability of both throwaway and saleable product FGD systems has been sufficiently demonstrated on full-scale units to warrant widespread commitments to FGD systems for SO_x control at coal- and oil-fired power plants.

(a) although some FGD installations in the U. S. have encountered reliability problems (primarily scaling, plugging, erosion, or corrosion), the panel finds that each of these problems can be solved through careful system design and proper control of system chemistry. Testimony at the hearing by utility and vendor witnesses revealed that all of the above problems have been solved at one or more full scale FGD installation in this country or Japan.

In reaching this conclusion the panel recognizes that operating parameters vary somewhat from plant to plant and that minor modifications of the basic FGD design will be required to optimize FGD operation on individual power plants. Operating experience at the following facilities is considered particularly important:

(1) Chemico Mitsui Miike Lime Scrubber - This unit has operated with near 100 percent reliability controlling a 156-megawatt coal-fired boiler near Omutu, Japan since its startup in March 1972. The panel finds that this unit has established that hydrated lime (calcium hydroxide) systems, operating generally in a closed-loop mode and occasionally subjected to varying loads, can operate for periods exceeding 1 year with no scaling, plugging, erosion, corrosion, or other significant operating problems.

(2) Louisville Gas & Electric's Paddy's Run Lime Scrubber - This unit has operated with good reliability since its startup in April 1973 and has reinforced the finding that closed-loop hydrated lime systems can operate reliably with proper chemistry control. This unit is particularly significant because pH control has been successful to date in achieving good operability despite wide variations in SO_2 inlet concentration and boiler loads.

(3) Japan Synthetic Rubber's Chiba Wellman-Lord System - This 70-megawatt facility, which produces high-quality concentrated sulfuric acid as the by-product, has operated with greater than 95 percent availability to the oil-fired boiler during over 2 years of operation. The panel believes that when efficient particulate removal equipment is installed upstream of the SO_x scrubbers, Wellman-Lord systems can operate reliably for extended periods of time on coal-fired boilers.

(b) the panel finds that the following commercially available FGD process/application combinations can be installed with the expectation of successful operability and reliability, in approximate order of confidence:

FGD System	Power Plant	By-Product
Wellman-Lord	Oil	Sulfuric acid
Lime scrubbing	Coal or Oil	Throwaway
Wellman-Lord	Coal	Sulfuric acid
Limestone scrubbing	Coal or Oil	Throwaway

A number of other FGD process/applications, such as magnesium oxide scrubbing (oil or coal), catalytic oxidation (oil or coal), Wellman-Lord (producing sulfur), and UOP/Shell (oil or coal), are not as fully demonstrated as the previously listed systems, and are expected to be demonstrated for full scale installations in the near future. Commitments can be made at the present time with good confidence that some of these systems will achieve a high degree of SO_x removal with acceptable reliability.

(c) the disposal of sludges produced by some types of FGD systems was cited throughout the hearing as a potential problem, and water pollution and land deterioration were named as two environmental complications. However, during the hearing, technology was described that can reclaim sludges for use as landfill at the many landfill sites available. In those cases where landfill is not economically practical due to a lack of available sites, regenerable-product or saleable-product FGD systems that do not produce throwaway sludges can be used. Fuel switching is also possible in such cases.

(d) the costs of installing FGD systems will vary depending upon many factors such as the type of power plant, space requirements, and the degree of control required. The panel finds that these costs, while substantial, are reasonable and will not impose an undue burden on either the electric utility industry or its customers.

(1) the hearing panel finds that the typical capital cost to install FGD on an existing plant will most commonly range from $50 to $65 per kilowatt of plant capacity. Capital requirements for the purchase of FGD equipment are estimated to be about $5.4 billion through 1980 to meet primary and new source performance standards, an increase of about 4 percent above expected power industry capital requirements without scrubbing.

(2) annual costs for operating FGD systems involve an annualization of capital costs plus such operating costs as those for waste disposal and for additional power to run the FGD system. The panel believes that the typical annual operating cost will range from 2 to 4 mills/kw-hr of power generated. The impact of this increased operating cost on consumers of electricity will vary depending upon the number of plants a given utility must control, and could result in a price increase of from 15 to 20 percent where control of most plants is required. Nationally, however, only about 30 percent of the projected coal-fired generating capacity will need FGD systems through 1980 to meet primary and new source performance standards; this can be expected to result in an average consumer cost increase of only about 3 percent.

(3) the increased electricity required to power an FGD system typically amounts to 4 to 7 percent of a plant's generating capacity. Based on EPA's estimate of the number of plants that will require FGD systems to attain primary standards, FGD installations will increase the national demand for electricity by only 1 percent through 1980.

(4) the cost of scrubbing may be prohibitive for plants with insufficient space or for older plants that will be retired shortly. Such plants should receive priority for available low-sulfur fuels.

(e) during the hearing, some utilities claimed that they should not be required to install FGD systems because they were unable to obtain lifetime reliability guarantees from vendors. Vendors have made substantial commitments to the development of FGD technology and generally offer guarantees for these systems that are comparable to the guarantees provided for other equipment purchased by a utility. No vendor is willing to assume all risks during the lifetime of the scrubber by guaranteeing its reliable operation at all times largely because the vendor rarely has control over the operation and maintenance of the system after the initial performance test. It is understandable that the utility industry is anxious to avoid risks, but the panel finds that guarantees now offered by vendors are appropriate and that the utility creating the pollution must assume the remaining risks associated with control of that pollution.

5. The utility industry has generally lacked a real incentive to develop FGD technology and to install this technology where needed to meet SO_x emission requirements.

(a) since FGD systems, unlike improved boiler designs, for example, do not result in more efficient generation of electricity, utilities do not have a profit incentive to develop and install these systems.

(b) vigorous enforcement of State SO_x emission requirements has not taken place in many cases, apparently as a result of the debate over whether FGD technology is sufficiently developed.

(c) while a number of State public utility commissions allow an automatic pass through (rate increase) of increased costs resulting from switching to a low-sulfur fuel, similar automatic pass throughs are not generally allowed for increased costs resulting from the installation of FGD systems. This tends to bias the industry toward fuel switching as a compliance mechanism.

(d) during the hearing many utility witnesses claimed that, because FGD technology is new, malfunctions of the FGD system would occur and would cause non-compliance. Although bypasses can be installed to prevent plant shutdown during malfunctions and although installation of control system redundancy and use of proper operating and maintenance procedures should reduce the occurrence of breakdowns, malfunctions will still occur that cause emissions to exceed the emission standards. Many States do not specifically provide for unpreventable malfunctions in their regulations, but use enforcement discretion to deal with such occurrences. Most power companies feel that more formal procedures should be developed; the hearing panel agrees.

Recommendations

On the basis of oral and written testimony presented during the hearing, the hearing panel recommends that:

1. The electric utility industry should:
   - (a) make immediate commitments to install FGD systems where needed to meet SO_x emission requirements, giving priority to those sources where controls are needed to meet primary ambient air quality standards and new source performance standards
   - (b) aggressively pursue FGD developmental programs to improve reliability, to lower operating costs and to advance FGD technology that results in a saleable by-product
   - (c) undertake further characterization and evaluation efforts on sludge disposal, with emphasis on large scale systems, to assure the widespread applicability and effectiveness of sludge disposal systems at reasonable costs
   - (d) hire (and train) personnel with the skills needed to properly design and operate FGD systems
2. EPA and the States should:
   - (a) create a strong incentive for the installation of FGD systems by establishing expeditious but reasonable compliance schedules and by vigorously enforcing these schedules
   - (b) formalize procedures for dealing with unpreventable control system malfunction where such formal procedures do not already exist

(c) urge State public utility commissions to treat increased costs from FGD control in the same manner as increased fuel costs are treated

(d) consider such other methods of creating an incentive to control SO_x emissions as the Administration's proposed charge (tax) on SOx emissions.

3. Compliance schedules established by the utilities, States, and EPA should:

   (a) be developed for each utility after considering the number and types of plants requiring FGD systems and the need to properly sequence installations to preserve utility power reserves

   (b) give priority to installation of FGD systems at those plants where systems are needed to meet primary ambient air quality standards and new source performance standards

   (c) require installation of FGD systems at a rate commensurate with vendor capacity

   (d) require, where feasible, the use of interim control measures such as intermittent control systems in order to minimize the impact of SO_x emissions on air quality until FGD systems can be installed

2. Background

Sulfur oxides are a major air pollution problem. Excessive quantities of this pollutant seriously affect human health through increased incidences of respiratory disease. Other adverse affects, such as increased metal corrosion and vegetation damage, are also caused by sulfur oxides.

The Clean Air Act, as amended in 1970 by the Congress, establishes strict requirements and timetables to clean our nation's air. The requirements of the Act demonstrated Congress' conviction that air pollution cannot be permitted to continue to menace the public health and welfare. Where health-related standards were involved, cost and difficulty of control were not to be issues in establishing the standards or the compliance schedules to meet them.

The Act required EPA to establish ambient air quality standards for significant air pollutants. These ambient standards were to be set at levels that would protect the public health and welfare from the adverse effects of air pollutants. In April of 1971, EPA promulgated primary (health-related) and secondary (welfare-related) ambient air quality standards for a number of air pollutants including sulfur oxides (SO_x).

Power plants are the major source of SO_x emissions in this country. In 1972 over 17 million tons of SO_x was emitted into our nation's air by power plants. These emissions accounted for nearly 60 percent of the total sulfur oxide emissions that year. Coal-fired power plants, by far the largest source, emitted nearly 16 million tons of SO_x, accounting for over 50 percent of the total SO_x emissions in 1972.

Emissions from power plants have been increasing each year along with our nation's demand for additional electric power. Total SO_x emissions from coal-fired power plants have increased from 10 million tons in 1963 to 16 million tons in 1972, and can be expected to continue to increase unless these emissions are controlled.

The impact of power plants on air quality varies across the country. In some areas the impact of power plants is relatively slight, but in other areas power plants alone cause primary standards to be exceeded. Use of high-sulfur coal, for example, is predominant in our East-Central States where such coal is mined. The detrimental impact of power plants on air quality in these States is substantial, especially when these States are compared to those where gas or low-sulfur oil is used as a fuel.

The Clean Air Act gave the States 9 months from the time EPA established ambient air quality standards to develop implementation plans containing emissions limitations sufficiently stringent to achieve the ambient standards. Each plan was tailored to the needs of the

State. Public hearings were held in each case. The plans were submitted to EPA early in 1972 and EPA approved or revised these plans by the middle of 1972. At that point, a year and a half ago, most major sources that needed to be controlled, including power plants, were subject to an emission limit enforceable by stringent civil and criminal penalties.

The Clean Air Act requires that schedules for compliance with these emission limits be established to ensure that the health-related ambient standards are met as quickly as possible, but not later than 3 years from the date of plan approval -- which is the middle of 1975. Limited extensions are provided for by the statute but only where strict criteria are met.

There are two general options which power plants have to achieve compliance with SO_x emission limitations. Sulfur oxide gases can be removed after combustion with flue gas desulfurization (FGD) systems, or emissions from the combustion process can be reduced by burning low-sulfur fuels. The latter option has been more commonly chosen since it is often the simplest route to compliance. A number of utility companies with coal-fired plants requiring significant reductions meet applicable emission limitations have recently accelerated purchases of coal naturally low in sulfur content, principally from western states. Western coal cannot, however, be used by many power plants because of its heat and ash characteristics. For plants where only moderate emission reductions are necessary, reduction of sulfur content by coal washing or by blending of present fuels with lower sulfur fuels may be sufficient to achieve compliance.

Unfortunately, the amount of low-sulfur coal available now and the amount that will be available in the 1975-1980 time frame will not be sufficient to permit all plants out of compliance to meet the SO_x emission limitations included in State implementation plans.[1,2] In addition, transporting large quantities of low-sulfur western coal to eastern plants would be expensive and would result in a failure to use readily available high-sulfur eastern coal reserves.

The current energy crisis will aggravate the existing shortage of low-sulfur fuels. A number of power plants now burning oil are expected to switch to coal soon and some oil-fired plants will no

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[1] Economic Impact Analysis of State Implementation Plan Regulations on Fuels and Energy Related Industries, Stephen Sabotka and Co., New York, NY, EPA Contract no. 68-01-0565, October 1972.

[2] Impact of State Implementation Plans of Fossil Fuels Availability and Requirements, MITRE Corporation, McLean, Va., EPA Contract no. 68-02-0248, August, 1972.

longer be able to obtain low-sulfur oil. The general shortage of low-sulfur fuels and the overall shortage of oil emphasizes this country's need to find an environmentally acceptable way of using our high-sulfur fuel resources.

Plants equipped with FGD systems can use high-sulfur fuels and still have emission levels equal to or even less than those resulting from the burning of low-sulfur fuels. With a substantial increase in the use of FGD systems, primary ambient air quality standards can be achieved in this decade.

Many existing State emission requirements are not tailored to give priority to controlling those sources that need to be controlled to achieve primary air quality standards. Shortages of low-sulfur fuels and the limited capacity of vendors to install FGD systems (discussed later in this report) make it especially important that appropriate priorities be established. EPA has urged a number of States to review their implementation plans and revise them to give priority to achieving primary ambient air quality standards.

Many utilities have suggested that tall stacks and other supplementary control systems, rather than equipment required to meet constant emission requirements, be allowed as a mechanism to achieve ambient air quality standards. Such supplementary control systems rely on the dispersion of pollutants rather than the constant reduction of pollutants. EPA considers constant emission reduction techniques such as flue gas desulfurization far superior to supplementary control systems. EPA proposed regulations in September 1973[3] that would limit the use of supplementary control systems to those situations where constant emission reduction techniques are not available and the only alternative is to shutdown the facility. Some forms of dispersion to reduce the impact of SO_x emissions on air quality may, however, be appropriate as interim measures for plants on schedules to achieve compliance through the use of constant emission controls.

There are about 970 fossil fuel steam-electric plants operating in the United States, with a total generating capacity of about 302,000 megawatts (1972 figures). Of this capacity, roughly 55% or 166,000 megawatts are coal-fired, 17% or 51,000 megawatts are oil-fired, and 28% or 85,000 megawatts are gas-fired.[4] Because SO_x emissions from the burning of natural gas are negligible, gas-fired plants were not considered in this hearing.

Many of the oil- and coal-fired plants were already in compliance with applicable sulfur oxide emission limitations before State implementation plans were developed. These plants had either undertaken control efforts, such as purchasing low-sulfur fuels, or were in areas where the sulfur dioxide ambient levels were not severe enough to warrant stringent emission limitations. Since the time when the implementation plans were approved, a number of additional plants have come or are coming into compliance by converting to fuels having lower sulfur contents and in some cases by installing FGD systems.

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[3] Federal Register, Vol. 38, September 14, 1973, p. 25697.

[4] Steam-Electric Plant Factors, 1972 edition, National Coal Association, Washington, D.C.

For the remaining noncomplying plants, EPA has attempted to determine the amount of flue gas desulfurization that will be needed nationally to assure timely attainment and maintenance of primary ambient air quality standards. This analysis was performed by looking at the need through 1980 for FGD on new and existing coal-fired plants and for oil-fired plants expected to switch to coal. Due to the uncertainties in the oil supply situation, it is not possible to analyze the need to retrofit existing oil-fired plants with FGD systems. The details and results of the analysis are discussed below.

To quantify the need for FGD for existing coal-fired plants, EPA used diffusion modeling techniques to determine how many of these plants have an impact on attainment of the primary standards. The projected growth of U.S. coal-fired capacity from the 1972 level of 166,000 megawatts to 209,000 megawatts in 1975 (EPA estimate) was taken into account. Of this 209,000 megawatts, some 123,000 megawatts are not expected to need any emission reductions to achieve primary standards; 23,000 megawatts are expected to need moderate reductions through such techniques as washing currently used coal or blending this coal with low-sulfur coal; and 63,000 megawatts are expected to need substantial reductions either through the use of low-sulfur coal or FGD.

EPA estimates that an average of 24,000 megawatts of new fossil fuel capacity will come into operation each year after 1975. Of this, about 14,500 megawatts will be coal-fired. Since many of these plants will not be able to comply with State emission requirements or Federal new source performance standards through the use of low-sulfur coal, they will greatly increase the need for FGD after 1975.

As indicated, a number of plants now using oil are expected to switch to coal because of oil shortages. Most of these plants will need to apply FGD systems in order to ensure attainment and maintenance of primary standards. The estimated additional scrubber needs for plants switching from oil to coal were added to the needs calculated for existing and new coal-fired plants.

Some utilities will be able to obtain low-sulfur coal for their plants. New supplies of low-sulfur coal will not be significant between now and 1975; however, limited supplies will be available after that time. By distributing our reserves and redistributing our current supplies of low-sulfur coal to the areas where they are most needed to attain air quality standards, current and projected supplies could significantly reduce FGD requirements after 1975. For this reason, estimated new low-sulfur coal supplies were taken into account in this analysis.

The results of the analysis are displayed in Figure 2-1. The curves in the figure show the maximum and minimum estimated FGD needs of those coal-fired power plants that need control for attainment of primary ambient air quality standards and attainment of EPA's new source performance standards. These curves include growth in coal-fired capacity from erection of new plants and expansion of existing plants, estimates of plants switching from oil to coal, the increase in supplies of low-sulfur utility coal, and the extent to which coal will be redistributed in response to SO_x emission limitations. FGD needs for oil-fired plants are impossible to estimate at this time and hence are not included. Inherent in this analysis is the assumption that power plants having an impact on primary standards will have priority in the distribution of low-sulfur fuels and FGD systems.

The high curve in Figure 2-1 indicates FGD needs if new low-sulfur coal supplies do not open up as anticipated, and if redistribution of existing supplies is minimal. The low curve represents optimistic projections of new supplies and extensive redistribution of currently used low-sulfur coal to areas where stringent emission reductions are needed.

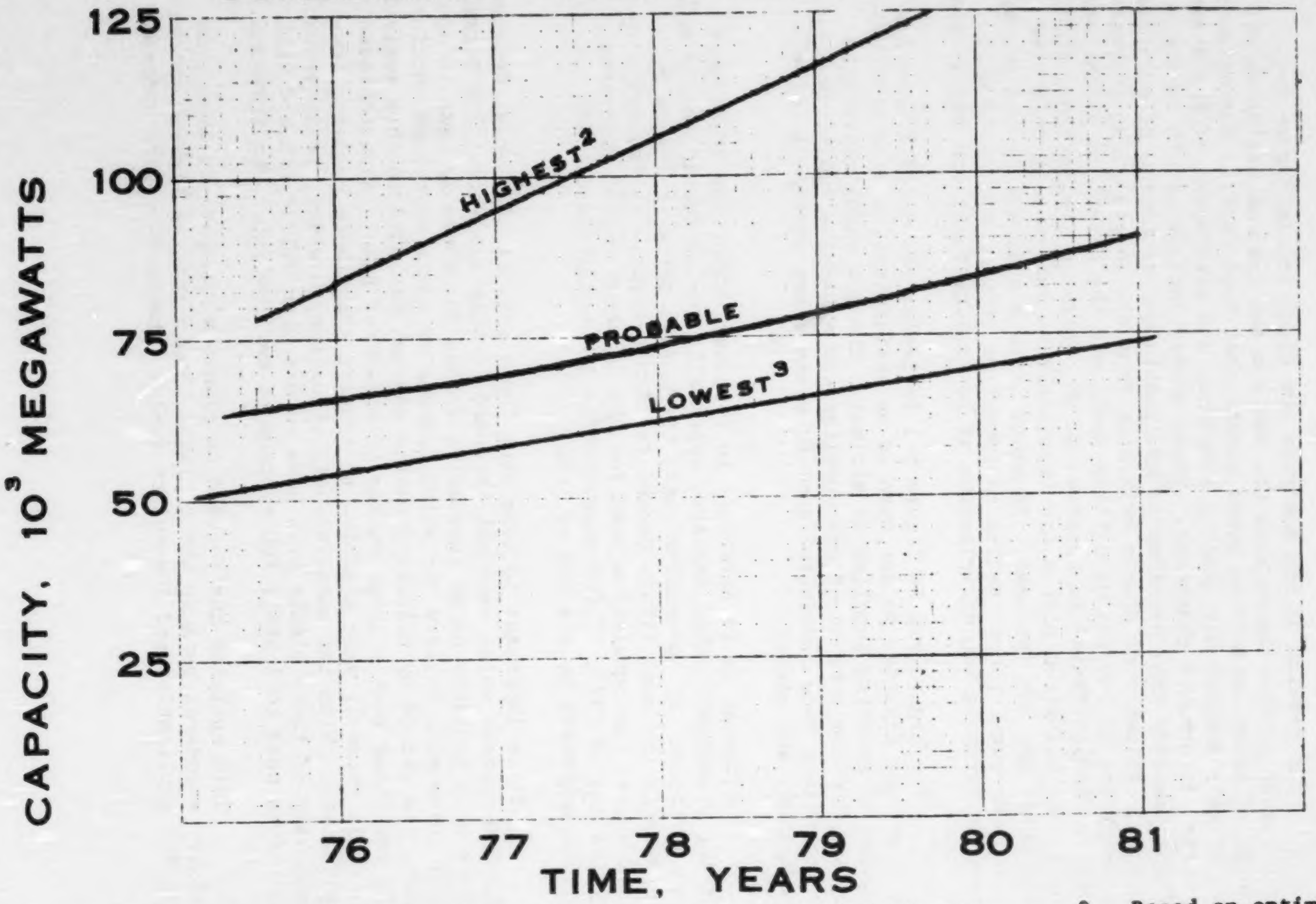
Although it is difficult to precisely determine the impact of the previously cited factors, especially the increased supply and redistribution of low-sulfur coal, the middle curve in Figure 2-1 represents the most likely demand for FGD systems. As indicated by this curve, the cumulative need for FGD is about 66,000 megawatts by the end of 1975, 73,000 megawatts by the end of 1977, and 90,000 megawatts by the end of 1980.

It is important to note that there will be additional demands for FGD systems which were not included in this analysis. For example, there will probably be an increasing demand for these systems to control industrial boilers for which low-sulfur fuels cannot be obtained. Also, the demand by oil-fired plants was not included in this analysis. EPA has found that a large number of oil-fired plants have achieved or until recently were planning to achieve compliance by using low-sulfur oil. With the uncertain oil situation, however, it is probable that many of these plants will have to use high-sulfur oil and will therefore need to install FGD systems to meet emission requirements.

This analysis has focused on plants which have an impact on primary standards because these plants should receive highest priority for FGD application and low-sulfur fuels. States have also adopted

FIGURE 2-1

CUMULATIVE NEED: FGD FOR COAL FIRED POWER PLANTS[1]



1. Includes new and existing coal-fired plants requiring controls to achieve primary standards or new source performance standards.

2. Based on pessimistic projections for new low sulfur coal supplies and minimal redistribution of existing supplies.

3. Based on optimistic projections for low sulfur coal supplies and maximum redistribution of existing supplies.

requirements to achieve secondary standards and to ensure that ambient standards are maintained in the future. These requirements must also be met and could add substantially to FGD requirements in the later 1970's.

3. Utility Compliance Efforts

Approximately half of the time allowed by the Clean Air Act to achieve compliance with health-related emission standards has now passed, and the mid-1975 compliance deadlines of most State implementation plans are only one and one-half years away. Any project to reduce SO_x emissions from a power plant (other than through reducing or halting operations) requires considerable time from initiation to completion.

In obtaining lower sulfur coals, a utility would spend time searching for the nearest source with the most convenient transportation, testing the new fuel in the boilers to determine its effect on the efficiency of combustion (as well as its effect on particulate control device efficiency), and negotiating a long term commitment from the supplier. Where a new source of coal is involved, mining operations must be initiated. The total process can take from several months to several years. As discussed later in this report, testimony at the hearing indicated that installation of FGD devices requires approximately 2 to 3 years. There was general agreement from all who testified that alternative forms of SO_x control, such as coal gasification and coal liquefaction, would not be available before the 1980's.

Obviously the one and one-half years remaining for compliance with most SO_x emission requirements will usually not be sufficient if a utility has not begun its compliance program. For this reason, one of the objectives of the hearing panel's questioning was to inquire into the status of utility compliance efforts.

The 20 electric utilities having witnesses at the hearing were representative of the U. S. electric utility industry. Testimony was heard from small utilities (such as Buckeye Power Co. and Kansas City Power and Light Co.) as well as from the large ones (such as the Tennessee Valley Authority (TVA), American Electric Power Service Corp. (AEP), and Ohio Edison Co.).

The utility witnesses generally agreed that supplies of low-sulfur fuel were insufficient and would remain insufficient for achieving compliance solely through fuel switching. In addition, many utilities expressed a strong desire, for economic and other reasons, to use locally available high-sulfur coal. Although FGD systems could bring these plants into compliance with SO_x emission regulations, few utilities testified that they had plans to install FGD systems where low-sulfur fuel was not available. On the basis of this testimony, and the time required to install FGD systems, it is clear that many SO_x emission requirements will not be met in a timely fashion.

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Table 3-1. FLUE GAS DESULFURIZATION STATISTICS, SEPTEMBER 1973[1]

	Operational	Under construction	Planned construction	Total	New plants	Retrofit on Existing Plant
Throwaway product						
Lime	4	6	1	11	7	4
Limestone	3	4	2	9	4	5
Aqueous Na based	-	3	-	3	-	3
Saleable product						
Wellman-Lord	-	1	-	1	-	1
Magnesium oxide	2	1	-	3	-	3
Cat-ox	1			1	-	1
Dry absorption	-	1	-	1	-	1
Process not selected						
Lime/limestone	-	-	10	10	4	6
No selection	-	-	5	5	4	1
TOTAL	10	16	18	44	19	25

PROJECTED START-UP DATE

1973	1974	1975	1976	1977
6	2	8	12	6

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[1] Transcript, Public Hearing and Conference on Status of Compliance with Sulfur Oxide Emission Regulations by Power Plants, U.S. Environmental Protection Agency, 4th & M Sts., SW, Washington, D.C. November 1973, F. Princiotta, EPA, pp. 42-48.

Table 3-2. PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

Limestone Scrubbing

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Commonwealth Edison Will County No. 1	R	156	B&W	Coal, 3.5%	Operational (Feb. 1972)
Kansas City Power & Light, Hawthorn No. 4	R	100	CE	Coal, 3.5%	Operational (Aug. 1972)
Kansas City Power & Light, LaCygne Sta.	N	820	B&W	Coal, 5%	Operational (June 1973)
Arizona Public Service Cholla Station	R	115	Research Cottrell	Coal, 0.4 - 1.0%	Under Construction (October 1973)
Detroit Edison St. Clair No. 6	R	180	Peabody Engineering	Coal, 3.7%	Under Construction (Dec. 1973)
Southern California Edison (operating agent) Mohave Sta.	R	160	UOP	Coal, 0.5 - 0.8%	Under Construction (March 1974)
TVA Widow's Creek No. 8	R	550	TVA	Coal, 3.7%	Under Construction (May 1975)
Northern States Power Sherburne County No.1	N	680	CE	Coal, 1%	Under Construction (May 1976)
Public Service of Indiana, Gibson Sta.	N	650	CE	Coal, 1.5%	Planned (1976)
Northern States Power Sherburne County No. 2	N	680	CE	Coal, 1%	Planned (May 1977)

Table 3-2 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

Lime Scrubbing

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Union Electric Co. Meramec No. 2	R	140	CE	Coal, 3%	Abandoned (Sept. 1968)
Kansas Power & Light Lawrence No. 4	R	125	CE	Coal, 3.5%	Operational (Dec. 1968)
Kansas Power & Light Lawrence No. 5	N	430	CE	Coal, 3.5%	Operational (Nov. 1971)
Kansas City Power & Light, Hawthorn No. 3	R	100	CE	Coal, 3.5%	Operational (Nov. 1972)
Louisville Gas & Electric Paddy's Run No. 6	R	70	CE	Coal, 3%	Operational (April 1973)
Duquesne Light Co. Phillips Station	R	100	Chemico	Coal, 2%	Under Construction (Nov. 1973)
Southern California Edison (operating agent) Mohave Sta.	R	160	SCE/Stearns-Roger	Coal, 0.5 - 0.8%	Under Construction (Dec. 1973)
Ohio Edison/Mansfield Sta. (2 units)	N	1650	Chemico	Coal, 4.3%	Under Construction (Early 1975)
Montana Power Colstrip No. 1 & 2	N	720	CEA	Coal, 0.8%	Under Construction (May 1975)
Columbus & Southern Conesville No. 5 & 6	N	750	Not Selected		Planned (1976)

Table 3-2 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

L/LS Not Selected

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Salt River Project Navajo No. 1	N	750	Not selected	Coal, 0.5–0.8%	Construction Start, Nov. 1974 (Mar.'76)
Salt River Project Navajo No. 2	N	750	Not selected	Coal, 0.5–0.8%	Construction Start, Oct. 1975 (Oct.'76)
Arizona Public Ser. Four Corners No. 1	R	175	Not selected	Coal, 0.75%	Construction Start, Oct. 1975 (Oct.'76)
Arizona Public Ser. Four Corners No. 2	R	175	Not selected	Coal, 0.75%	Construction Start, Nov. 1975 (Dec.'76)
Southern California Edison (operating agent) Mohave No. 1&2	R	1180	Not selected	Coal, 0.5–0.8%	Planned (Dec. 1976)
Arizona Public Ser. Four Corners No. 3	R	229	Not selected	Coal, 0.75%	Construction Start, June 1976 (Mar.'77)
Salt River Project Navajo No. 3	N	750	Not selected	Coal, 0.5–0.8%	Construction Start, Mar. 1976 (Mar.'77)
Arizona Public Ser. Four Corners No. 4	R	800	Not selected	Coal, 0.75%	Construction Start, Sept. 1975 (Apr.'77)
Arizona Public Ser. Four Corners No. 5	R	800	Not selected	Coal, 0.75%	Construction Start, Nov. 1976 (June '77)

Table 3-2 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Magnesium Oxide Scrubbing					
Boston Edison Mystic No. 6	R	150	Chemico	Oil, 2.5%	Operational (April 1972)
Potomac Electric & Power Dickerson No. 3	R	100	Chemico	Coal, 2%	Operational (Sept. 1973)
Philadelphia Electric Eddystone No. 1	R	120	United Engineers	Coal, 2.5%	Under Construction (Dec. 1973)
Other SO_2 Control Systems					
Catalytic Oxidation (Cat-Ox)					
Illinois Power Co. Wood River No. 4	R	110	Monsanto	Coal, 3.2%	Operational (Oct. 1972)
Wellman-Lord					
Northern Indiana Public Service, D.H.Mitchell No.11	R	115	Davy Powergas/ Allied Chemical	Coal, 3.5%	Under Construction (Early 1975)
Aqueous Sodium Base Scrubbing, Non-Regenerable					
Nevada Power Reid Gardner No. 1&2	R	250	CEA	Coal, 0.5 - 1.0%	Under Construction (Dec. 1973)
Nevada Power Reid Gardner No. 3	R	125	CEA	Coal, 0.5 - 1.0%	Under Construction (1975)
Dry Adsorption					
Indiana & Michigan Electric, Tanner's Creek Station	R	150	B&W/Esso	Coal,	Under Construction (1974)

Table 3-2 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

Process Not Selected

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Public Service of New Mexico San Juan No. 2	R	100	Not Selected	Coal, 0.8%	Planned (Nov. 1974)
Potomac Electric & Power Chalk Point No. 3	N	630	Not Selected	Oil	Planned (1975)
Potomac Electric & Power Chalk Point No. 4	N	630	Not Selected	Oil	Planned (1976)
Potomac Electric & Power Dickerson No. 4	N	800	Not Selected	Coal, 2%	Planned (1976)
Potomac Electric & Power Dickerson No. 5	N	800	Not Selected	Coal, 2%	Planned (1977)

Table 3-3. COMPARATIVE COST FIGURES FOR PRIVATELY OWNED ELECTRIC UTILITIES[2]

($$10^3$)

	1969	1970	1971	1972
Total electric operating revenues	$18,022,904	$19,791,066	$22,321,874	$25,3[illegible],868
Total research & development expenditures	$41,026	$46,037	$94,390	$175,343
Total R & D - % of Total operating revenues for electric utilities	.23%	.23%	.42%	.69%

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[2] *Statistics of Privately Owned Electric Utilities in the United States, 1971*, and unpublished 1972 edition of the same publication. Federal Power Commission, Washington, D.C. Publication no. FPC-S226. October 1972.

Most electric utility representatives testified that their companies were reluctant to install full scale FGD systems on large numbers of plants. There was general agreement that FGD systems can, when working properly, achieve the 85 to 90 percent reduction required to meet the emission limits, but most utilities argued that FGD systems were plagued with problems such as unreliable operation, high cost, and sludge disposal difficulties. These alleged problems are discussed in some detail in later sections of this report. The remainder of this section reviews the efforts made by electric utilities to solve what they considered to be the major problems with FGD systems.

Only 22 of the some 300 electric utilities of all types operating fossil-fueled plants in the United States have installed, or are committed to install, at least one FGD unit. Table 3-1 breaks down by type the 44 FGD systems (controlling about 18,000 megawatts of generating capacity) that have been installed or are planned by these 22 utilities; and Table 3-2 shows these FGD systems by type and company. Of course, some research and development on FGD systems could be accomplished without the installation of full scale systems; hence, it is important to review the industry's overall research and development effort. Total electric utility industry research and development, although increasing over the last few years (see Table 3-3), is very small and amounted to less than 1 percent of the industry's total operating revenue in 1972. Research and development on FGD systems is only a small but undetermined part of this overall effort.

Although research efforts by the utility industry as a whole have lagged, several utilities (generally the smaller ones) have undertaken vigorous FGD programs. Kansas City Power & Light Co., Louisville Gas & Electric Co., Potomac Electric Power Co., and Arizona Public Service Co. account for 17 of the 44 units mentioned above. Louisville Gas & Electric Co. testified that FGD was more economical and more in the interest of the State of Kentucky than was fuel switching.[3] Compliance schedules have been submitted to progressively install scrubbers on eight existing and two new Louisville Gas & Electric Co. plants by 1980.[4] Although Kansas City Power & Light Co. is not subject to sulfur oxide emission regulations, it too has initiated a program to install FGD systems on all its plants. These and a few other utilities have made substantial efforts to develop FGD technology even though most of them do not yet believe the technology to be fully demonstrated. As the spokesman for Arizona Public Service Co. said, the lack of demonstration is not an excuse for a utility to do nothing.[5]

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[3] Testimony, J. F. Mayrose, Louisville Gas & Electric Co., p. 1200.

[4] Testimony, J. F. Mayrose, Louisville Gas & Electric Co., pp. 1205-1218.

Unfortunately, most of the other utilities that testified did not evidence aggressive programs to solve the alleged problems in applying FGD. These utilities have generally adopted a 'wait and see' attitude and have apparently been content to point out all the problems while waiting for each other or for FGD vendors to solve them. Indeed, some companies appear to have spent more in defending their lack of progress or in attempting to have the requirements changed than they have in controlling their sulfur oxide emissions. Many examples of this attitude were evident during the hearing and the following serves to illustrate this point.

Although representatives of West Penn Power Co. testified that contracts to obtain low-sulfur coal for several of its power plants had been initiated, it was acknowledged that this supply would be inadequate for the company as a whole.[6] Yet West Penn Power Co.'s work on FGD development has been minimal and, in fact, no one person was working full time on FGD technology until just prior to the hearing.[7] Of the four expert witnesses for West Penn Power Co., three were hired the month before the hearing to prepare the company's testimony; the fourth, a meteorologist, had been in the employ of the company for 2 years as a general consultant on air quality problems.[8]

AEP, like West Penn Power Co., has attempted to obtain locally available low-sulfur coal to achieve compliance. The company, which is the second largest user of coal in the U. S., acknowledged that nearby low-sulfur coal would be available for only 60 to 70 percent of their coal-fired generating capacity.[9] Although AEP claimed that its name "is synonymous with pioneering"[10] in such new technologies as cooling towers, extra high voltage transmission lines, and supercritical boilers, this large company is not pursuing any significant research program of its own on FGD systems.

AEP pointed out a number of problems with FGD systems, yet contended that it was common sense to await the outcome of current FGD demonstration programs at other utilities before attempting even a pilot operation of its own. AEP's program for bringing the rest of its system into compliance is dependent upon the availability of low-sulfur coal from western States, the expectation of an easing in the degree of control required by some State emission standards, and the allowance of tall stacks for SO_x abatement.[11]

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[5] Testimony, C. McVay, West Penn Power Co., pp. 376-379.

[6] Testimony, C. McVay, West Penn Power Co., pp. 376-379.

[7] Testimony, C. McVay, West Penn Power Co., pp. 389-390.

[8] Testimony, C. McVay, West Penn Power Co., pp. 391-393.

[9] Testimony, J. Dowd, American Electric Power Co., pp. 2641-2645.

[10] Testimony, J. Dowd, American Electric Power Co., p. 2636.

The Tennessee Valley Authority is the largest utility in the United States, producing about 10 to 15 percent of the country's electricity as well as a commensurate share of emissions from coal-fired power plants. Except for requesting variances from the three states in which it operates, TVA testified that no plans had been formulated to comply with SO_x emission limitations because TVA believed that these regulations were under review in each State.[12] It was TVA's contention that achieving ambient air quality levels by reducing the amount of pollutants being emitted rather than dispersing contaminants through the use of tall stacks and intermittent controls was a "terrible mistake".[13] Although TVA is building a full scale FGD system for one boiler at its Widows Creek Station and has participated in several EPA-funded FGD research programs since 1967, the company admitted to expending greater efforts in attempting to change State regulations than in developing FGD technology. In addition, TVA stated that its program would not change even if the utility decided that FGD technology had been adequately demonstrated.[13]

Testimony from utilities that have installed FGD systems and from vendors of these systems indicated that control of system chemistry is critically important for reliable operation. Such operation is, however, unique to companies experienced with power generation but unfamiliar with the control of chemical processes. Unfortunately, only a few companies testified to having hired personnel skilled in chemical operations. Those who have, such as Louisville Gas & Electric Co., seem to have had the most reliable FGD operation.

It seems clear that utility witnesses understood and agreed that Congress' mandate to control sulfur oxide emissions would be met in a timely way only through the application of FGD technology. Most utilities argued that this technology was not yet adequately demonstrated, but few of these companies aggressively pursued solutions to the alleged FGD system problems. In general, utilities have been content to wait for other utilities and FGD vendors to solve these problems. The general 'wait and see' attitude of the utility industry toward FGD systems is even less acceptable since many of these companies have not aggressively followed the work of those companies that have installed FGD systems. TVA, for example, testified that they had not visited the Louisville Gas & Electric Co. installation until one month prior to the hearing[14] even though this FGD system had been in operation for 6 months and was only a short distance from TVA's headquarters. This approach is not responsive to the mandate of the Clean Air Act and the utility industry must, in the future, mount a much more aggressive program to determine solutions to its compliance problems.

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[11] Testimony, J. Dowd, American Electric Power Co., pp. 2638-2645.

[12] Testimony, L. Seeber, Tennessee Valley Authority, p. 2339.

[13] Testimony, L. Seeber, Tennessee Valley Authority, p. 2343.

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[14] Testimony, W. Elder, Tennessee Valley Authority, p. 2336.

4. Status of Flue Gas Desulfurization Technology

It was generally agreed at the hearing that FGD technology, when operating properly, can reduce sulfur emissions to the required levels (up to 85 or 90 percent removal). Key questions were raised, however, about the reliability, waste disposal problems, and costs associated with these systems. This section of the hearing report deals with the issue of scrubber reliability and operability. Waste disposal problems and costs associated with flue gas desulfurization are dealt with in other sections.

Although the hearing testimony on the status of FGD technology can be roughly divided into two opposing viewpoints, only a few speakers took the extreme positions that FGD technology will not be ready for commercial applications for many years or that it is now fully optimized. Most utilities stated that FGD technology is not ready for commercial application; estimates of time required for further development ranged from a few months to over 5 years. Louisville Gas & Electric Company seemed to be the most optimistic of the utilities, indicating that only a few more months of operation at their Paddy's Run Station is required prior to commitments to full commercial-scale systems.[1] They described the major constraints on widespread application to their generating system as nontechnical. Several utilities took the position that development has progressed to the point where large scale (single module) installations are warranted for continued development and demonstration, even though reliability has not yet been demonstrated.

Equipment vendors represented at the hearing were generally optimistic concerning the status and future of FGD. Seven vendors (Peabody, CEA, Chemico, Research Cottrell, CE, Davy Powergas, and UOP) stated that they are now prepared to offer full scale commercial systems. Certain vendors indicated that they favored some pilot work for applications with unusually high-sulfur or high-ash fuels concurrent with full system design. In some cases, modular installation was considered the desired approach although substantial additional time for full control is required.

Lime/Limestone FGD Technology

Lime Scrubbing - The process is offered commercially by Chemico, Combustion Engineering, Inc. (CE), and Combustion Equipment Associates, Inc. (CEA). The Mitsui unit built by Chemico (a U.S. firm) has operated reliably since April 1972 on a 156-megawatt coal-fired boiler in Japan.[2] A Combustion Engineering-designed system has been successfully operating at Louisville Gas and Electric's Paddy's Run Station since April of 1973. No problems have developed with this installation and it shows promise of successful long term operation.

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[1] Testimony, J. F. Mayrose, Louisville Gas & Electric Co., p. 1236.

Limestone Scrubbing - The process is offered commercially by Babcock & Wilcox, Peabody Engineered Systems, Research Cottrell (RC), and CE. Although there is currently no full scale system operating which can be considered a successful demonstration, several systems are now undergoing intermittent operation and modification to solve operating problems. These installations include Will County, Hawthorn, and LaCygne. The recently started Cholla unit of Arizona Public Service seems to hold promise of successful operation during the coming year. The results of the EPA Shawnee prototype facility have been encouraging.

Reliability Problems

The bulk of the testimony relevant to the reliability question centered around lime/limestone scrubbing systems, which represent the great majority of FGD systems installed or planned to date.

For lime and limestone FGD systems, the following major reliability problems were cited by W. D. Crawford,[3] A. Slack,[4] and J. Bradstreet[5] as evidence that FGD technology is not sufficiently developed for utility applications:

- chemical scaling in the scrubber
- plugging (demister and wet/dry interfaces)
- mechanical problems (fans, pumps, etc.)

During the course of the hearing it became apparent that, based on testimony from expert witnesses, there were design provisions which can, and have, at selected installations, resolved all of the above problems. Dr. Craig[6] representing Edison Electric Institute commented during panel questioning on the above problems by stating: "Many of those problems are well underway to having adequate solutions to them... The Mitsui (Chemico 156-megawatt lime scrubber in Japan) operation, for one example, has not experienced to any great degree many of those problems."

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[2] Testimony, F. Princiotta, EPA, p. 56A.

[3] Testimony, W. D. Crawford, Edison Electric Institute, p. 880.

[4] Testimony, A. Slack, SAS Corp., representing West Penn Power Co., pp. 165-197.

[5] Testimony, J. Bradstreet, NUS Corp., representing Public Service Co. of Indiana and NIPSCO, pp. 561-579.

[6] Testimony, J. Craig, Southern Services, Inc., p. 991.

The following summarizes some testimony relevant to these problem areas:

Chemical Scaling (Hard chemical deposits)

Dr. Craig[7] stated that "...in a well-operated system in a well-operated plant, plugging apparently has been overcome. Scaling is apparently well underway to being controlled. Mitsui (Chemico lime scrubber in Japan) did experience some slight amount of scaling, but nothing of the order of magnitude which would cause it to be shutdown." Louisville Gas & Electric[8] indicated that during the 6 months of operation of their unit scaling was not a significant problem. Dr. Hesketh[9] from Southern Illinois University indicated that scaling was not a significant problem at the Mitsui installation during its 20 months of operation, which he described as generally operating in a closed-loop manner. EPA[10] indicated that scaling has not been a significant problem during the operation of limestone and lime reliability testing to date at their Shawnee prototype facility. In general, the following provisions were cited in testimony as capable of reducing the tendency toward scaling problems: high liquid/gas ratios, proper scrubber selection, high percentage of solids, and probably most importantly, careful pH control within certain limits.

Plugging (Soft solids buildup)

As stated earlier in a quote from Dr. Craig (EEI), the problem associated with "plugging apparently has been overcome". Again, Louisville Gas & Electric and Dr. Hesketh testified that problems associated with plugging (including demisters) have not been significant during the operation of the Paddy's Run and Mitsui Miike Power Plant lime FGD systems, respectively. EPA[10] described the initial problems experienced at the Shawnee facility with demister pluggage, and modifications which were made to apparently resolve these problems. Commonwealth Edison, although plagued with demister pluggage problems since their start-up during February 1972 stated:[11] "...the plugging problem that we have had in our demister, due to a recent modification in washing arrangement, it looks like we might have that one under control." Generally, careful design of demisters and their wash systems appears effective in eliminating demister pluggage. Careful design of wet/dry interface locations was cited as having been effective in alleviating other pluggage problems.

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[7] Testimony, J. Craig, Southern Services, Inc., p. 992.

[8] Testimony, R. VanNess, Louisville Gas & Electric Co., pp. 1229-1230.

[9] Testimony, H. E. Hesketh, Professional Engineer, p. 2763.

[10] Testimony, F. Princiotta, EPA. pp. 2513-2517.

Erosion/Corrosion

Under cross-examination Dr. Craig[12] stated that "we are well on the way toward eliminating erosion problems." He indicated that "...engineering judgments, selection of materials could eliminate erosion and corrosion problems". He went on to say "...it will take time to apply what we currently have available and optimize what we currently have available". Again, Louisville Gas & Electric and Mitsui facilities have reported no significant erosion/corrosion problems during the operation of their lime scrubbers. The Mitsui unit is particularly significant since there has been no deleterious erosion/corrosion since its startup in March 1972. It should be noted that those utilities which were scrubbing with large quantities of fly ash in the slurry and/or did not control pH have experienced erosion/corrosion of varying magnitudes.

Mechanical Problems

Mechanical problems were cited by several utilities as major difficulties. Reliability of pumps, fans, and other important process equipment has sometimes not been adequate. It was not clear whether these problems were due to: poor choice of equipment, poor quality control, maloperation, etc. However, these problems are not generally process related, and have not, in fact, been significant at several installations to date, including Louisville Gas & Electric and Mitsui Aluminum.

Table 4-1 presents a summary of testimony regarding observed problems, by problem area, for important lime/limestone and other full-scale/prototype facilities. In general, all problems identified at a given installation have been resolved at another installation; in addition, Mitsui Aluminum (lime), Louisville Gas & Electric (lime), and Japan Synthetic Rubber (Wellman-Lord) have not experienced significant difficulties in any of the problem categories.

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[11] Testimony, D. Gifford, Commonwealth Edison, speaking for Edison Electric Institute, p. 1008.

[12] Testimony, J. Craig, Southern Services, Inc., p. 1012.

Table 4-1. FGD OPERATING PROBLEMS AND THEIR RESOLUTIONS AT VARIOUS PLANTS*

Problem	JSR Chiba Plant	Comm. Ed. Will County	Mitsui Chemico Plant	Boston Edison Mystic	EPA Shawnee	K.C.P&L LaCygne	Louisville G&L Paddy's Run
Chemical scaling	No	Minor	No	No	No	Minor	No
Demister pluggage	No	Yes	No	No	No	Yes	No
Wet/dry pluggage	No	No	No	No	No	No	No
Erosion/corrosion	No	Yes	No	Minor	Minor	Yes	No
Reheater problems	No	Yes	No	No	No	Yes	No
Mechanical problems (Fans, pumps, dryers, etc.)	No	Yes	No	Yes	No	Yes	Minor
Date started up	July 1971	Feb. 1972	Mar. 1972	Apr. 1972	Apr. 1972	Feb. 1973	Apr. 1973
Process	Wellman-Lord	Limestone	Lime	Magnesium oxide	Limestone & lime	Limestone	Limestone
Oil or coal	Oil	Coal	Coal	Oil	Coal	Coal	Coal
Size, megawatts	75	156	156	150	3x10 Mw	840	70
Testimony	S. Watt, Davy Powergas, pp. 2426-2450	B. Lee, Comm. Edison, pp. 2067-2206	H. Hesketh, So. Ill. Univ pp. 2741-2768	W. Irving Boston Ed., pp. 1356-1386	F. Princiotta EPA, pp. 35-110	D. McPhee, KCP&L, pp. 1436-1451	J. Mayrose LG&E, pp. 1198-1219

*Yes or No indicates whether problems were considered serious at time of hearing.

The Relevance of the Mitsui Lime Scrubber

The most controversial lime/limestone FGD facility, and potentially the most important to the question of reliability, is the 156-megawatt Chemico lime scrubbing facility at Mitsui's Miike Station near Omutu, Japan. EPA[13] has stated that the success of this unit, which has operated reliably (by all accounts) since its start-up in March 1972, is quite relevant to many U. S. applications; the following areas of similarity were cited:

(1) Retrofit on an existing coal-fired boiler
(2) Installation on a moderately large size boiler (156 megawatts)
(3) Availability of calcium hydroxide ($Ca(OH)_2$) in U. S.
(4) Based on U. S. (Chemico) technology

Several utility witnesses, including A. Slack,[14] mentioned several apparent differences between the Mitsui installation and typical U. S. applications, which they felt tended to diminish the relevance of this unit. The following major areas of "non-relevancy" were cited:

(1) Use of carbide sludge, a form of calcium hydroxide, at Mitsui vs. more available burnt lime form in U. S.

(2) Base load operation at Mitsui vs. widely varying boiler loads associated with many U. S. applications

(3) Open-liquor-loop operation at Mitsui which tends to minimize scaling problems yet results in a water pollution problem unacceptable in the U. S.

There was, however, much substantive testimony presented which tended to minimize the importance of the so-called differences between the Mitsui facility and U. S. applications.

With regard to the use of carbide sludge at Mitsui, R. VanNess,[15] who is intimately familiar with carbide sludge production and is responsible for the Louisville G & E carbide sludge scrubber, said: "I don't think there is any difference" between burnt lime and carbide sludge. Dr. Hesketh, the professor from S. Illinois University, who has performed the most intensive evaluation of the Mitsui system, stated that lime is more reactive than carbide sludge due to smaller particle size and

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[13] Testimony, F. Princiotta, EPA, p. 57.

[14] Testimony, A. Slack, SAS Corp., representing West Penn Power, Co., p. 166.

[15] Testimony, R. VanNess, Louisville Gas & Electric Co., p. 1232.

"...chemically, I do not believe there is a difference between calcium hydroxide produced by carbide sludge and calcium hydroxide produced from the slaking of lime."[16] Combustion Engineering,[17] after testing both materials in their Windsor pilot facilities, also stated they did not think there were any important differences between these materials.

With regard to noncycling (base) load operation at the Mitsui facility, it was noted by Dr. Hesketh[18] that: "I feel there have been a number of times when this system (Mitsui) has been cycled, and during these periods of cycling, the pH control, which seems to be one of the very significant factors in keeping the unit from scaling up and shutting down, has been maintained at desired levels. There have been no problems." Also, Mr. VanNess indicated that pH control has been generally successful at the Louisville G & E's Paddy's Run lime unit, which has experienced pronounced variable load operation. He stated: "control is a chemical one and pH control is very, very important in this... This tends to be a very complicated control system, and I think we have tended to master this, not absolutely completely, ...but so far we had some very encouraging results".[19]

With regard to the alleged open-loop operation at Mitsui, the only testimony with factual back-up was presented by Dr. Hesketh who performed detailed material balances around the Mitsui system. He stated: "This operation operates completely in closed-loop operation. Very few times does it operate in an open-loop."[20]

Dr. Hesketh summed up his thoughts on the relevance of the Mitsui unit by stating: "...we have already had the statement that the technology is here, it can be made to go, and I agree very definitely with this. We have got to make it go because that's what they are doing in Japan."[21]

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[16] Testimony, H. Hesketh, Professional Engineer, p. 2761.

[17] Testimony, J. Jonakin, Combustion Engineering, Inc., p. 1312.

[18] Testimony, H. Hesketh, Professional Engineer, p. 2763.

[19] Testimony, R. VanNess, Louisville Gas & Electric Co., p. 1229.

[20] Testimony, H. Hesketh, Professional Engineer, p. 2762.

[21] Testimony, H. Hesketh, Professional Engineer, p. 2765.

Wellman-Lord Sodium Based Scrubbing

This process is offered commercially by Davy Powergas, Inc. Davy reported that this regenerable process has been operating since August 1971 on a 75 megawatt oil-fired boiler at the Japanese Synthetic Rubber Plant at Chiba, Japan.[22] This unit has exhibited a 97 percent availability to the boiler for more than 2 years. An additional unit at Chubu Electric Company was started up in May 1973. This 220-megawatt unit is subjected to wide variations in both load and inlet sulfur concentration. Operation of the Chubu unit has been trouble-free. There are no technical or reliability problems associated with the Wellman-Lord process as applied to oil-fired utility boilers. Davy Power Gas stated that coal-fired flue gas should not present any difficulties provided adequate particulate removal is incorporated in the system. The panel questioned the extent to which Davy was considering the potential environmental problems associated with the sodium sulfate purge stream which is characteristic of the process. The Davy representative indicated that certain processes were being examined for treatment or elimination of the purge and that for limited cases it may be possible to market the sodium sulfate.[23] No specifics regarding these alternatives were provided, however. Also, the panel indicated that the use of critical natural gas in conjunction with the Allied reduction process was a constraint on use of the W-L/Allied process. It is true, however, that the W-L process is also used to produce acid as a product without the need for natural gas. Generally the testimony given on this process was of a positive nature. Subsequent to this testimony, there was little disagreement with the points made.

Magnesium Oxide Scrubbing

The first commercial-size application of this process was installed by Chemico on a 155-megawatt oil-fired boiler at Boston Edison's Mystic Station. Since starting the system up in April 1972, considerable efforts have been made to improve the system's reliability. One of the problems encountered was with magnesium sulphite crystal size; fine particles passed through the dryer, the mechanical collector, and out the stack; particles that were too large also caused problems, probably realted to hydration reactivity. These problems have been solved by rerouting the dryer discharge containing the fine crystals back into the scrubber itself and recycling, and by the installation of grinders to get more uniform consistency of crystal size, respectively.[24] In response to a question regarding problems inhibiting a long-term reliable run, N. Irving of Boston Edison testified to the effect that "They all seem solvable with the technology that we have today" and that "we see no mechanical or technical reasons why this will not be a successful project."[25]

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[22] Testimony, Stewart Watt, Davy Powergas, p. 2442.

[23] Testimony, Stewart Watt and C. Earl, Davy Powergas, pp. 2459-2463.

[24] Testimony, W. Irving, Boston Edison Co., pp. 1376-1377.

Testimony presented by R. Blinckmann of Chemico indicates that they consider the process technology to have been adequately demonstrated at Boston Edison. They feel that adequate reliability is yet to be demonstrated but expect to offer the process on a full-scale commercial basis for oil-fired units within the next several months.[26] Chemico will not offer the process commercially for full scale coal-fired applications until process technology and reliability have been adequately demonstrated at the 100-megawatt system at PEPCO's Dickerson Station, which started-up in September 1973.

An additional system employing a variation of the Chemico process is being installed by United Engineers at Philadelphia Electric's coal-fired Eddystone Station on a 120-megawatt boiler. This system is scheduled to start up in early 1974.[27]

With these three systems in operation, it is anticipated that expansion of process applicability as well as improvements in reliability will be rapid in the coming months.

Other FGD Processes

The Cat-Ox System, which was developed by Monsanto, has been installed on a 100-megawatt coal-fired boiler at Illinois Power's Wood River Station. The demonstrating unit has been operated for a short period of time and control efficiency and capability to produce the specified acid product were verified and the process proven. However, reliability and economics of operation and maintenance of equipment are factors yet to be determined and are hence still unproven.[28] Efforts to determine these factors have been delayed due to nonavailability of natural gas for reheating of the flue gas prior to the catalyst bed. Modification is currently underway to permit reheat with No. 2 fuel oil. Restart is expected in the Spring of 1974. Additional problems encountered include condensation of acid in bypass ductwork with resulting corrosion and failure of expansion joints permitting acid leakage. Inadequate expansion joints have been replaced by better ones.[29] Illinois Power seems optimistic that reliable operation will be achieved in 1974 following completion of the oil-fired reheat burner modifications.

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[25] Testimony, W. Irving, Boston Edison Co., p. 1385.

[26] Testimony, R. Blinckman, Chemical Construction Corp., p. 1884.

[27] Testimony, V. S. Boyer, Philadelphia Electric Co., p. 1928.

[28] Testimony, E. Schultz, Illinois Power Co., p. 1618.

In addition to the four major processes mentioned earlier and the Cat-Ox process discussed above, UOP stated that they are offering the Shell FGD process on a commercial basis.[30] In addition, the double alkali process shows promise of advancing to commercialization in the not too distant future. The Japanese Chiyoda process is finding widespread acceptance in Japan and will be tested in the U. S. in the near future.

Technology Summary

The panel finds that technological feasibility of FGD systems has been established. Both throwaway and saleable product FGD technology have demonstrated sufficient reliability on full scale units to warrant widespread application for SO_x control at many coal- and oil-fired power plant applications with acceptable risks.

Although some U. S. installations have encountered reliability problems, the panel finds that each of these problems can be solved through careful system design and proper control of system chemistry. Testimony at the hearing revealed that all of the above problems have been solved at one or more full scale FGD installation in this country or Japan.

Operating experiences at the following facilities are considered particularly important:

(1) Chemico Mitsui Miike Lime Scrubber - This unit has operated with near 100 percent reliability controlling a 156-megawatt coal-fired boiler near Omutu, Japan since its startup in March 1972. The panel finds that this unit has established that hydrated lime (calcium hydroxide) systems, operating generally in a closed-loop mode, subjected to occasional varying loads, can operate for periods exceeding 1 year with no scaling, plugging, erosion, corrosion or other significant operating problems.

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[29] Testimony, E. Schultz, Illinois Power Co., p. 1655.

[30] Testimony, S. Mleczko, Universal Oil Products Co., p. 2572.

(2) Louisville Gas & Electric's Paddy's Run Lime Scrubber- This unit has operated with good reliability since its startup in April 1973 and has reinforced the finding that closed-loop hydrated lime systems can operate reliably with proper chemistry control. This unit is particularly significant because pH control has been successful to date in achieving good operability despite wide variations in SO_2 inlet concentration and boiler loads.

(3) Japan Synthetic Rubber's Chiba Wellman-Lord System - This 70-megawatt facility, which produces high-quality concentrated sulfuric acid as the by-product, has operated with greater than 95 percent availability to the oil-fired boiler during over 2 years of operation. The panel believes that when efficient particulate removal equipment is installed upstream of the SO_x scrubbers, Wellman-Lord systems can operate reliably for extended periods of time on coal-fired boilers.

The panel also finds that the following commercially available FGD/process application combinations can be installed with a high probability of successful operability and reliability, in approximate order of confidence:

FGD System	Fuel	By-Product
Wellman-Lord	Oil	Sulfuric Acid
Lime Scrubbing	Coal or Oil	Throwaway
Wellman-Lord	Coal	Sulfuric Acid
Limestone Scrubbing	Coal or Oil	Throwaway

A number of other FGD process/application combinations such as magnesium oxide scrubbing (oil or coal), catalytic oxidation (oil or coal), Wellman-Lord (producing sulfur), and UOP/Shell (oil or coal), while not yet as fully demonstrated as those systems discussed above, are expected to be demonstrated on full scale installations in the near future.

5. Vendor Guarantees

During the hearing, some utility industry witnesses expressed dissatisfaction with guarantees being offered by vendors of FGD systems. The chief drawback, as seen by these witnesses, was the refusal of vendors to provide consequential damages or reliability guarantees. Consequential damages involve payment by the vendor for power or revenue lost during outages, and liability for such damages is almost universally declined by vendors, not only for FGD systems, but for nearly all equipment supplied to power plants.[1] Because the guarantees offered by vendors are limited, there is a risk involved in installing an FGD system just as there is a risk involved in installing electric generating equipment. It is understandable that utilities are reluctant to assume the risks involved, but the Act clearly demands that the industry creating the pollution undertake whatever risks are associated with control of that pollution. Inability to obtain provisions covering consequential damage or reliability does not, contrary to industry opinion, mean that FGD technology should not be installed.

It is important to note that guarantees for FGD systems are similar to those offered for such other major equipment purchased by utilities as boilers, turbines, and electrical equipment. Table 5-1 describes guarantees usually provided by vendors; purchase contracts for nearly all major equipment and for FGD systems are similar and few contracts ever include provisions for consequential damages liability or for reliability guarantees.

Guarantees are invariably a part of bid specifications and purchase agreements for all of the equipment used by power plants. Typical contracts include a performance guarantee and a warranty against defects in material and workmanship. Performance guarantees for air pollution control equipment usually specify a period of time during which the equipment will achieve a given removal efficiency under specific conditions (e.g., additive feed rate, gas throughput). The vendor's liability is commonly limited to some fraction of the purchase price; seldom is the full purchase price refunded if the system fails to meet guaranteed performance. Guarantees against defects in material and workmanship cover the basic design and mechanical integrity of the system and the specifications for construction materials, but do not normally cover erosion, corrosion, or normal wear.[2] The value of the guarantee is usually limited to replacement of the item or reimbursement of a portion or all of its purchase price.

It should be noted that vendors often make repairs not required by the contract in order to protect their good reputation. However, no

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[1] Testimony, H. P. Willet, Peabody Engineered Systems, p. 2294.

[2] Testimony, Sidney R. Orem, Industrial Gas Cleaning Institute, p. 1858.

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Table 5-1. Usual Business Practices

Guarantees or Warranties Provided

1. System performance of efficiency guarantee

   a. The system supplied is guaranteed to meet the performance requirements of the contract as demonstrated by a short-term test on startup or within one year following date of first commercial operation.

   b. In the event the system fails to meet guaranteed performance, the vendor will absorb the full expense of materials and labor on a straight time basis.

   c. Performance tests cannot be delayed for more than 30 days after the vendor gives notice to the purchaser that the equipment is ready for testing.

2. Materials and workmanship warrantee

   a. The system is warranted to be free of defects in material or faulty design for one year from date such material or equipment is placed in use, or 18 months from date such material is shipped, whichever occurs first.

   b. In the event that any material or equipment is found to be defective or fails under design operating conditions, the vendor shall redesign and furnish F.O.B. shipping points replacement or repair parts.

   c. The vendor does not warrantee components of the systems manufactured by subcontractors.

   d. The vendor is not responsible for damage to the system caused by operating under conditions not in accordance with the vendor's written instructions.

   e. The vendor is not responsible for replacement of material and equipment which is damaged or becomes defective as a result of corrosion, erosion, or normal wear-and-tear.

3. Liability limitations

   The total liability of the vendor is limited to a maximum amount equal to the value of the system not including the auxiliary equipment not manufactured by the vendor or the erection labor or alternatively to the vendor's profit.

Guarantees or Warranties Not Provided

1. System reliability

   a. A guarantee that the equipment will be operable for a specified percentage of time after the performance test for even short-term periods is not a usual business policy of vendors.

   b. U.O.P. stated that their company would provide a 75% reliability guarantee for one year with their FGD system for oil-fired boilers. Liability is probably limited to the cost of the equipment, similar to performance guarantees.

2. Consequential damages

   a. Liability for loss of profit on sales of electric power due to equipment breakdown is declined by vendors.

   b. Liquidated damage provisions relating to a definite construction completion date and to a performance level are sometimes accepted as part of a bonus-penalty contract provision.

3. Operating and maintenance expenses

   a. Vendors do not guarantee operating expenses. Projections of these expenses are included in the vendor's bid proposal. These proposals receive close engineering evaluation by the utility to determine which system has the greatest potential for lowest cost operation.

   b. Maintenance costs for normal wear-and-tear during the one-year warranty period and all maintenance costs in subsequent years including repair of breakdowns are not absorbed by the vendor except on a voluntary basis.

vendor is willing to assume all risks during the lifetime of the FGD system by guaranteeing its reliable operation at all times because the vendor rarely has control over the operation and maintenance of the system after an initial performance test. Only one vendor, Universal Oil Products Co., stated a willingness to guarantee reliability (75 percent), and then for only 1 year with the reservations that the vendor would operate the control device and that liability was limited to the purchase price.[3] However, vendors have, in general, taken substantial risks in developing FGD systems. Combustion Engineering, Inc., for example, invested $20 million to develop a system, and estimates that it will be another 20 years before this investment can be recovered in profits.[4]

The panel finds that FGD system guarantees now offered by vendors are generally appropriate and that the demands put forth by the industry are often unreasonable, not in accord with usual business practices, and clearly not in accord with the requirements of the Act. For example, AEP demanded a guarantee for a proposed FGD system that was unprecedented in any of their previous equipment contracts. AEP wanted an iron-clad guarantee that the installed equipment would function nearly trouble-free for 15 years handling coal with a sulfur content up to 5.5 percent. Design was to be completed less than 9 months after the contract was awarded and the system was to be operating full scale in time to comply with 1975 standards. The equipment was to complete its first year as a "demonstration period," and if the system failed, the vendor would be liable for 150 percent of the contract price. The vendor would also have been liable for consequential damages of up to $53 per megawatt per day for any downtime beyond 5 days a year for the remaining 14 years of the guarantee.[5] This same utility characterizes itself as a leader in the industry and a pioneer in supercritical boilers. AEP took a risk in installing the first 100-megawatt supercritical boiler with no provision for consequential damages or any reliability guarantee, but is not willing to install pollution control equipment under the same conditions.[6] The difference may be in the incentive for the utility to take the risk. Supercritical boilers result in lower generating costs, but there is no cost incentive for AEP to install a pollution control system.

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[3] Testimony, Stanley S. Mleczko, Universal Oil Products Co., p. 2596.

[4] Testimony, James Jonakin and Joe Singer, Combustion Engineering, Inc., pp. 1284-1289.

[5] Testimony, Thomas N. Bethell, United Mine Workers of America, p. 1959.

[6] Testimony, J. Tillinghast, American Electric Power Service Corp., pp. 2684-2686.

6. Flue Gas Desulfurization System Malfunctions

Because FGD technology is relatively new, unpreventable malfunctions might be expected during operation of the system. Many States have no regulatory provisions that exempt sources from emission limits during periods of malfunction. Some industry witnesses claimed that this creates a difficult situation because boilers must be shutdown during malfunctions to prevent emissions from exceeding permissible limits; this would result in a loss of revenue and in a loss of needed electricity. Witnesses claimed that the only alternative is to maintain operation of the generating system and face the possbility of being found in violation of applicable regulations. Some members of the utility industry therefore argue that the large capital investment necessary to control SO_x emissions cannot be justified until the industry is assured that emission limits will not apply during periods of unpreventable malfunction.

The panel, however, finds that this concern is somewhat overstated. It is not always necessary to shutdown a boiler during malfunction; rather, ducting can be installed to bypass the equipment during malfunction. In addition, about one-half of the States already have statutes that provide relief from emission limitations during malfunctions. New Mexico's regulation is typical. It provides that unpreventable malfunctions do not constitute a violation of the applicable regulations if certain procedures are followed.[1] The source must report the breakdown to the State agency within a designated period of time, make a maximum reasonable effort to correct the problem, and minimize excess emissions during the breakdown. In addition, the regulation requires that a report be made to the State after the malfunction has been corrected.

Although the other 50 percent of States do not have specific regulations covering malfunctions, very few States automatically take enforcement action when a source exceeds emission limits during a malfunction. Pennsylvania, for example, does not take any enforcement action until it has carefully studied the malfunction and determined the cause of the breakdown.[2] If the malfunction occurred despite the company's efforts to operate the equipment effectively and if the company responds to the situation by making the maximum reasonable effort to correct the problem and prevent its recurrence, Pennsylvania does not bring an enforcement action.

Because AEP believed that West Virginia had no regulatory provisions exempting sources from emission limitations during malfunctions,[3] the company conditioned its acceptance of a bid to install sulfur oxide control equipment at its Kammer Station on the inclusion of a guarantee

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[1] Transcript, Cubia Clayton, New Mexico Environmental Improvement Agency, p. 1531.

[2] Transcript, Clark L. Gaulding, Penna. Department of Environmental Resources, pp. 2970-2974.

[3] Transcript, Richard M. Dicke, Simpson, Thacker and Bartlett, appearing on behalf of American Electric Power Co., p. 2663.

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that the control equipment would be as reliable as various components of the generating system. Breach of this guarantee would require the vendor to pay the cost of the control equipment plus consequential damages. Noting that equipment vendors were not anxious to meet the terms of this bid specification, AEP concluded that "(There should be an) accommodation, if you will, by the regulator, to the reasonable needs of the industry and the manufacturers by specifically promulgating regulations."[3]

AEP, however, failed to specifically discuss malfunction provisions with West Virginia.[4] Carl Beard, Director of the West Virginia Air Pollution Control Commission, testified that a specific provision allowing for a variance during malfunction was adopted in West Virginia on February 1, 1973.[5] It would seem that better communication with the State agency would have brought this fact to AEP's attention.

Although the lack of formal malfunction procedures has not proved to be a problem in the past, the panel believes that such procedures should be formalized by States lacking such regulation.

FGD systems malfunction for several reasons. When pumps and other mechanical equipment breakdown, the scrubbers will not operate, but this does not affect the generating system. The control system can simply be bypassed, allowing untreated gas to pass through. A malfunction caused by plugging or corrosion does necessitate more than taking the scrubber off-line; a bypass to shunt the flue gas around the control equipment to the stack must be used.

Two types of bypass systems are currently used by utilities. The simplest system is one that uses blanking plates to close off the ducts leading to the scrubbers. Plates are mounted on rollers and manually moved into position. The primary deficiency in this system is the necessity of shutting down the boiler during plate movement. Shutdown time is a function of the manpower available to position the plates. One to three days are normally needed to shutdown the boiler, position the plates, and refire the boiler.

A more complicated but less time consuming system uses mechanical dampers activated when the control equipment malfunctions. The dampers in these systems are either the guillotine-type which slide down into the path of the flue gas or the louvre-type which close, thereby blocking the gas stream.

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[4] Transcript, J. Dowd, American Electric Power Co., p. 2675.

[5] Transcript, C. Beard, West Virginia Air Pollution Control Commission, pp. 2709-2711.

Representatives from several utilities using such dampers testified at the hearing that these systems often do not operate because of mechanical failures. The corrosive flue gas causes the dampers to "freeze," either in the open or closed position. When the dampers freeze in the open position, pressure buildup can cause boiler seals to blow out. To prevent this, boilers are often shutdown. Freezing of the dampers in the closed position results in excess stack emissions after the malfunction in the scrubber system has been corrected.

Control equipment vendors do not view the bypass system problem with the same gravity as do industry representatives. It is the vendors' opinion that the problems associated with bypass dampers are minor and can easily be solved by proper control design and by the installation of good quality dampers manufactured from material that does not react with the corrosive gas stream.[6]

Louisville Gas & Electric Company's experience with the bypass system at its Paddy's Run Station supports this view. Although the dampers are not 100 percent effective, the company reports good results with the system.[7]

The hearing panel recognizes that difficulties can be expected in the use of damper systems, especially when such systems are installed in ducts having large cross-sectional areas. However, the panel finds that the problems experienced by the utilities are not major and can be solved through proper design and workmanship.

In order to improve the overall reliability of scrubbing systems, many vendors oversize their control systems by 20 to 33 percent. This oversizing can be effected in a number of ways. Extra scrubbers can be installed which come on-line when the primary scrubbers malfunction, or individual scrubbers can be designed to operate normally at less than 100 percent capacity.[8] In addition, extra mechanical components such as fans and pumps can be fitted into the individual scrubbers.

Although most utilities do acknowledge that redundancies lower the rate of malfunctions, many do not feel that the added expense is justified in every case. For example, in a control system for a plant in the 100 to 200 megawatt range, installation of a backup scrubber could increase the capital outlay by 100 percent. Accordingly, some small stations do not and should not put on extra units. Some types of redundancy are appropriate for some sources and not for others; appropriate redundancies can be determined only on a individual basis.

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[6] Transcript, Robert H. Quig, Chemical Construction Corp., pp. 1903-1904.

[7] Transcript, Robert VanNess, Louisville Gas & Electric Co., pp. 1224-1225.

[8] Transcript, Jack B. Moore, Southern California Edison, p. 1795.

Although many utilities testified that when an FGD system malfunctions the plant would have to be shutdown if it is to remain in compliance with SO_x limitations, testimony on available bypass systems and on existing State regulations and procedures does not support this contention. The panel, however, urges those States that have not already done so to formalize procedures for dealing with malfunctions. The panel also finds that appropriate control system redundancies should be determined on a case by case basis.

7. Waste Disposal

During the hearing the electric utility industry evidenced concern for disposing of sludges created by FGD systems. However, not all types of FGD systems generate sludge. Some regenerable systems reduce the captured SO_2 to a much more compact form. The disposal problem is minimized or eliminated with such systems. FGD systems therefore fall into two categories: "saleable product" systems and "throwaway" systems. Saleable product systems produce such materials as sulfuric acid and sulfur which can be marketed in many locations in the U. S. Throwaway systems produce semisolid wastes, generally referred to as sludge, that require the use of waste disposal technologies. Such wastes, produced by wet lime, limestone, and double alkali systems, contain various proportions of calcium sulfite, gypsum, fly ash, water, and assorted other materials in trace quantities.

Nearly all representatives of EPA, utilities, and FGD system vendors stated or implied that sludge disposal was a significant problem having potential environmental implications. Representatives of Environmental Sciences, Inc. (Chemfix) and I.U. Conversion Systems, Inc. (IUCS), two companies commercially offering sludge fixation/disposal services, testified that technology is available at reasonable cost for fixation and disposal of sludge in an environmentally acceptable manner.[1,2] Dr. Minnick of IUCS stated that "our organization is prepared to finance, construct, and operate processing facilities for the treatment of fly ash and sludge for a specific fee per amount of waste product handled, and is in a position to prepare definitive cost proposals on a long-term service agreement basis for utilities having disposal problems."[2] Although there was no testimony given by Dravo or Chicago Fly Ash, two other companies that offer sludge fixation/disposal services, allusion to their technology and activities was made by other witnesses. It should be noted that the historical power plant problem of coal fly ash disposal has been handled for each plant in operation today; in fact, testimony by IUCS brought out the fact that their company was in that business.[2]

EPA discussed the potential environmental problems created by scrubber sludges: water pollution and land deteoriation. Surface waters such as rivers, streams, lakes, and ponds can be contaminated following rainfall by runoff or discharge from sludge disposal areas or by water balance problems in the scrubber system. Ground water can be contaminated by leaching and percolation of sludge liquor into the ground water through soil in sludge storage areas. Land deterioration could result from having to store on large areas of land large amounts

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[1] Testimony, J. Conner, Environmental Sciencies, Inc., pp. 3050-3070.

[2] Testimony, L. J. Minnick, I.U. Conversion Systems, Inc., pp. 2768-2787.

of sludge materials typically containing 50 to 70 percent water and having a "toothpaste-like" consistency. This land could be made useless by the nonsettling characteristics of the sludge. To minimize the potential environmental problems created by FGD system sludges, the liquor must be recycled to the scrubber while the remaining wet solids are either ponded in a nonpermeable pond or are solidified for landfill or other disposal. The liquor and dissolved chemical species must be entrapped physically and/or chemically in the solid matrix. This is the basis of the technology offered by Dravo, IUCS, Chemfix, and Chicago Fly Ash.

Although this technology is offered commercially, it has not been used to date on any full-scale control system other than at Commonwealth Edison Co. where a process developed by Chicago Fly Ash Co. is being used. Both Dravo and IUCS, however, are planning to process sludge from future systems. Dravo expects to process sludge from the 100-megawatt system at the Phillips Station of the Duquesne Light Co. scheduled for startup in December 1973 and from the 1650-megawatt Bruce Mansfield plant of the Ohio Edison Co. scheduled to startup in 1975.[3,4] Dr. Minnick of IUCS testified that IUCS expects to operate a sludge fixation/disposal system at an unidentified full-scale utility plant by the beginning of 1974.[5] The Chemfix process of Environmental Sciences, Inc. was applied to samples of sludge from Commonwealth Edison Company's Will County plant and from the TVA Shawnee plant.

The costs discussed for treatment of sludge vary substantially. The highest cost mentioned was $17.10 per ton of dry solids, which was cited by Commonwealth Edison Co. as the actual operating cost for the Will County Station for treating thickener sludge with the Chicago Fly Ash process from May through September 1973.[6] This is equivalent to 2.24 mills per kilowatt-hour or about 22 percent of the total FGD system operating cost. Duquesne Light Co. estimated the cost for sludge fixation treatment using Dravo's technology at their Phillips Station at $14 to $15 per ton of dry solids or about 1.2 mills per kilowatt-hour.[7] The IUCS estimate is $1.5 to $3.0 per ton of dry solids or about 0.2 to 0.3 mills per kilowatt-hour, exclusive of dewatering equipment and hauling

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[3] Testimony, S. L. Pernick, Duquesne Light Co., p. 1578.

[4] Testimony, D. W. Tschapport, Ohio Edison Co., p. 2212.

[5] Testimony, L. J. Minnick, I. U. Conversion Systems, p. 2786.

[6] Testimony, Byron Lee, Commonwealth Edison Co., p. 2086.

[7] Testimony, Steve Pernick, Duquesne Light Co., 1590.

costs. Dr. Minnick indicated that disposal site availability is an important variable affecting cost because long distance hauling can be quite expensive.[8] No costs for the Environmental Sciences Chemfix process were cited in the testimony.

Most of the commercially offered sludge fixation technology is considered proprietary by the vendor. However, all of the vendors claim that they can dispose of calcium sludge in an environmentally acceptable manner if they are given samples of the material to experiment with; they must tailor their process to the specific sludge in question. Although the IUCS process was stated to be proprietary by Dr. Minnick, he did admit that fly ash is an essential ingredient to the fixation process.[9] In general, however, the ratio of fly ash to calcium-sulfur compounds produced at most power plants using lime or limestone FGD systems is favorable to the fixation process.

Both IUCS and Environmental Sciences, Inc., suggested that solidified sludges may have uses other than landfill. Some of the uses cited include construction material for dikes and retaining walls, road base, and construction aggregate.

The issue of sludge leachability was brought up several times during the course of the hearings. Environmental Sciences, Inc. has attempted to develop standard test methods to determine the degree of leachability of fixed solid waste. These methods were described, and some comparisons of treated and untreated sludge leachate samples were shown. The treatment appears to reduce soluble contaminant concentrations considerably. Both Environmental Sciences, Inc. and IUCS claim to be capable of making a solid waste product that is environmentally acceptable from the standpoint of leachability. However, regulatory standards for levels of soluble solids in landfill materials were not cited.

In summary, the disposal of sludge produced by throwaway FGD systems was cited throughout the hearing as a potential problem. However, the panel finds that during the course of the hearings, technology was described that could minimize or eliminate the associated environmental problems. This technology includes closed-loop operation, use of pond liners, and chemical treatment (fixation) enabling disposal of sludge as an acceptable landfill material at the large number of landfill sites that are available for sludge disposal. There are, however, specific cases, generally in urban areas, where sludge disposal could be prohibitively expensive due to a lack of readily available landfill sites. Regenerable or saleable product FGD systems which do not produce throwaway sludges should be considered for these applications; fuel switching could also be used to achieve compliance. Utilities are urged to move ahead quickly with developmental work on ponding and fixation technology. Further characterization and evaluation efforts, with emphasis on large scale systems, are needed to assure wide spread applicability and effectiveness at reasonable costs.

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[8] Testimony, L. J. Minnick, I.U. Conversion Systems, pp. 2780-2781.

8. Costs of Flue Gas Desulfurization Systems

One of the most important and perhaps most elusive issues discussed at the hearing was the cost of installing and operating FGD systems. Almost every witness referred in some way to the cost of controls and a number of witnesses gave cost figures based on their own experience or on the experience of others. The most objective way to assess the cost of FGD systems is to look at the cost estimates discussed at the hearing for specific plants. These cost figures, including capital and annual costs, where given, are summarized in Table 8-1.

As shown in Table 8-1, testimony regarding capital costs for retrofitting FGD systems on existing plants ranged from as low as $39 per kilowatt to as high as $108 per kilowatt. Most estimates fell in the range of $50 to $65 per kilowatt. Capital costs for new plants were generally lower.

Annual costs for retrofitted plants ranged from 2.4 mills/kw-hr to a high of 10 mills/kw-hr, with most plants falling in the 2.4 to 4.0 range. Only two estimates of annual costs for new plants were given -- EPA's estimate of 1.5 mills per kw-hr and Ohio Edison Co.'s estimate of 2.7.

It is difficult to compare the cost figures in Table 8-1 because many of them include different items in the costs or are based on different assumptions. For example, some cost estimates include the cost of building sludge disposal ponds while others include the assumption that sludge would be hauled away. Others factors, such as the age of the plant, peculiar retrofit and operating problems, variations in sulfur content, degree of control required, annual load factors, amount of redundancy, vendor guarantee specifications and different time bases, also caused variations in the costs. Some of these factors are included in the comments column in the table.

The cost of flue gas desulfurization may be prohibitive for plants having severe space limitations. In addition, the annualized cost of retrofitting older plants may be severe if the plant will be retired shortly. The hearing panel therefore suggests that these plants have first priority for available low-sulfur fuels.

The costs of installing and operating FGD systems will ultimately result in increased costs to the consumer. The costs cited above constitute increases in costs at the individual plants, but the amount of corresponding increase that must be passed on to the consumer depends upon the number of plants within the particular system that need control. The most straightforward example is the case where a customer is in an area served by a utility company having only one

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plant. If this plant must install control that will result in an increase of 3 to 4 mills/kw-hr in annual costs, then the consumer's rates could increase by as much as 15-20 percent annually (assuming that the consumer had been paying the typical rate of 20 mills/kw-hr). However, companies commonly have several plants and in this case, the consumer's costs would not be as severe. In fact, as discussed in the Background section of this report, only about 90,000 megawatts of power plant capacity will require FGD by 1980 in order to meet primary air quality standards. Using 3 mills/kw-hr and a 7.5 percent annual inflation factor, this amounts to an increase in the average price of electricity of only about 3 percent by 1980.[1]

Most State public utility commissions provide for automatic pass-throughs (rate increases) of increased fuel costs caused when a utility switches to more expensive low-sulfur fuel as an emission control mechanism. Similar automatic pass-throughs are not generally allowed for the installation of control devices such as FGD systems; this tends to make switching to scarce low-sulfur fuel a preferred control alternative. The panel feels that State public utility commissions should treat increased costs from FGD control in the same manner as increased fuel costs are treated.

The capital cost to the utility industry of installing FGD, while substantial, will not be great in comparison to projections of total future capital investments of the industry. Using an average of $60 per kilowatt, the 90,000 megawatts of scrubbing needed by 1980 to meet primary standards amounts to an investment of about $5.4 billion. Assuming an annual inflation rate of 7.5 percent, the installation of scrubbers will increase the industry's capital requirements only 4 percent through 1980 (based on a projected expenditure of $195 billion between 1974 and 1980 for generation and transmission facilities).[1]

Included in the cost of flue gas desulfurization is an energy penalty resulting from the operation of the scrubber. This amounts to a penalty of 4 to 7 percent of energy produced at an individual plant.[2] Nationwide, however, this energy penalty is not large in comparison to the environmental benefits received. Using a national average of a 5.5 percent energy penalty for those plants operating FGD systems, the total electricity used by FGD systems in 1980 will only be about 1 percent of the total electricity projected to be used in that year.[1]

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[1] Economic and Financial Implication of the Federal Water Pollution Control Act of 1972 for the Electric Utility Industry, prepared under EPA contract no. 68-01-1582, Temple, Barker and Sloane, Inc., Wellesley Hills, Massachusetts, September 1973.

[2] Testimony, Frank Princiotta, EPA, p. 38.

The hearing panel finds that while the costs of installing and operating needed FGD systems will be substantial, the overall national costs will not impose an undue burden on either the electric utility industry or its customers. Although the national costs discussed above are based only on FGD needs to meet primary ambient air quality standards, the additional needs to meet other requirements of State implementation plans are not expected to be so large as to change this conclusion.

TABLE 8-1. CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Lime/Limestone systems - Retrofit							
---	Typical	200	52	2.4	Estimate	Assumes 80% load factor. Annual costs include facilities for waste disposal and environmental controls to minimize land and water pollution.	Princiotta, EPA, p. 55
Northern Indiana Public Service	Bailly 7,8	615	62	---	Estimate	Does not include sludge ponds (Not enough land for on-site disposal.)	Kuhlman, Sargent & Lundy (NIPSCo consultant), p. 589
Northern Indiana Public Service	Bailly 7,8	615	47	4-6	Estimate	Does not include sludge ponds. Capital investments required for sludge treatment included. Annual costs include fixation and hauling. 55% load factor.	Gerstle, PEDCo (EPA consultant), pp. 660-661

TABLE 8-1 (continued). CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Public Service Co. of Indiana	Wabash River	880	68	3.2	Estimate	Includes sludge disposal area facilities. 68% load factor.	Kolflat, Sargent & Lundy (PSI consultant), p. 703A
Public Service Co. of Indiana	Wabash River	880	66	3.7	Estimate	Sludge disposal included. Sludge pumping included in annual costs. 66% load factor.	Gerstle, PEDCo (EPA consultant), pp. 820-821
Detroit Edison	St. Clair	170	50	---	Estimate	Includes pond for sludge disposal but not the cost of land.	Willett, Peabody Engineering (Detroit Edison, vendor) p. 2282
West Penn Power	Mitchell	470	62	4	Estimate	Does not include sludge pond costs (pond is already constructed). Annual costs include sludge fixation and hauling. 70% load factor.	Gerstle, PEDCo (EPA consultant), p. 429

TABLE 8-1 (continued). CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Louisville Gas & Electric	Paddy's Run	70	57	---	Experience		Mayrose, LG&E, pp. 1242-1243
Public Service Co. of New Mexico	San Juan 1,2	670	45-60	---	Estimate		Geist, Pub. Service Co. of N. Mexico, pp. 1478, 1486
TVA	Widows Creek 8	550	76	---	Estimate		Seeber, TVA, p. 2318
Duquesne Light	Phillips	380	70-75	2.11	Estimate & experience	Annual cost does not include annualized capital costs.	Pernick, Duquesne Light, p. 1566
Commonwealth Edison	Will County 1	155	108	10	Experience	Includes sludge treatment. 35% load factor.	Lee, CommEd, pp. 2079-2080
Lime/Limestone Systems - New Plants							
---	Typical	1000	35	1.5	Estimate	Assumes 80% load factor. Costs include facilities for sludge disposal and environmental controls for land and water pollution.	Princiotta, EPA, p. 55

TABLE 8-1 (continued). CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Kansas City Power & Light	LaCygne 1	820	42	---	Experience		McPhee, KCP&L, p. 1436
Ohio Edison	Mansfield	1600	93	2.7	Estimate	Capital costs include sludge disposal. Assumed 100% load factor.	Mansfield, Ohio Edison, p. 2170
Commonwealth Edison	Powerton 6	840	72-86	---	Bids		Lee, CommEd, p. 2079 Also in CommEd's written submittal dated 10-12-73 III-D-6
MgO Systems - Retrofit							
Boston Edison	Mystic 6	155	39	---	Estimate & experience	Includes cost of calciner facility but not of acid plant (acid plant is responsibility of chemical contractor)	Irving, Boston Edison, p. 1363
Cat-Ox Systems - Retrofit							
Illinois Power	Wood River	880	77	3	Experience (capital costs) Estimate (annual costs)	68.5% load factor.	Shultz, Illinois Power, pp. 1611-1612

9. Time Requirement for Installation of Flue Gas Desulfurization Systems

One of the aims of the hearing was to determine the time required to install flue gas desulfurization systems on power plants. Much information was brought out on this subject; a total of some 17 organizations presented their views, based on either estimates or actual experience. The installation times discussed ranged from 27 to 48 months for direct installation of full scale FGD systems and from 41 to 54 months for full scale systems installed in the course of a modular or developmental program. The time estimates were distributed by witness experience as indicated below. (Figures were adjusted to a common basis.) Details on individual inputs are given in Table 9-1.

Experience of Witness	Number of Inputs	Time from Decision to put in SO_2 Control to Compliance (months)
Actual installations	6	27 to 36
Estimates by EPA consultant	1	27
Estimates by utilities and utility consultants	3	36 to 48
Estimates by vendors	2	30 to 36
Various estimates involving a modular or developmental program	5	41 to 60

The greatest weight should be given to the testimony concerning the actual time it took to install currently operating systems. Installation times will, of course, vary with the situation. Variables affect-the time requirements include the size of the plant, the type of FGD system installed, and the difficulty of retrofit.

The testimony leads the panel to conclude that the time necessary to install a full scale FGD system will generally be from 27 to 36 months from decision to install FGD to compliance with emission regulations. This can be broken down into the following stages: signed contracts in 6 to 9 months, construction begun in 8 to 11 months, startup in 21 to 30 months, and compliance in 27 to 36 months.

This schedule could be shorter or longer, depending upon the many factors affecting particular installations. These include such localized factors as labor, parts delivery, and more general factors such as the limited vendor capacity discussed in this report. An important consideration in scheduling is the restriction on when

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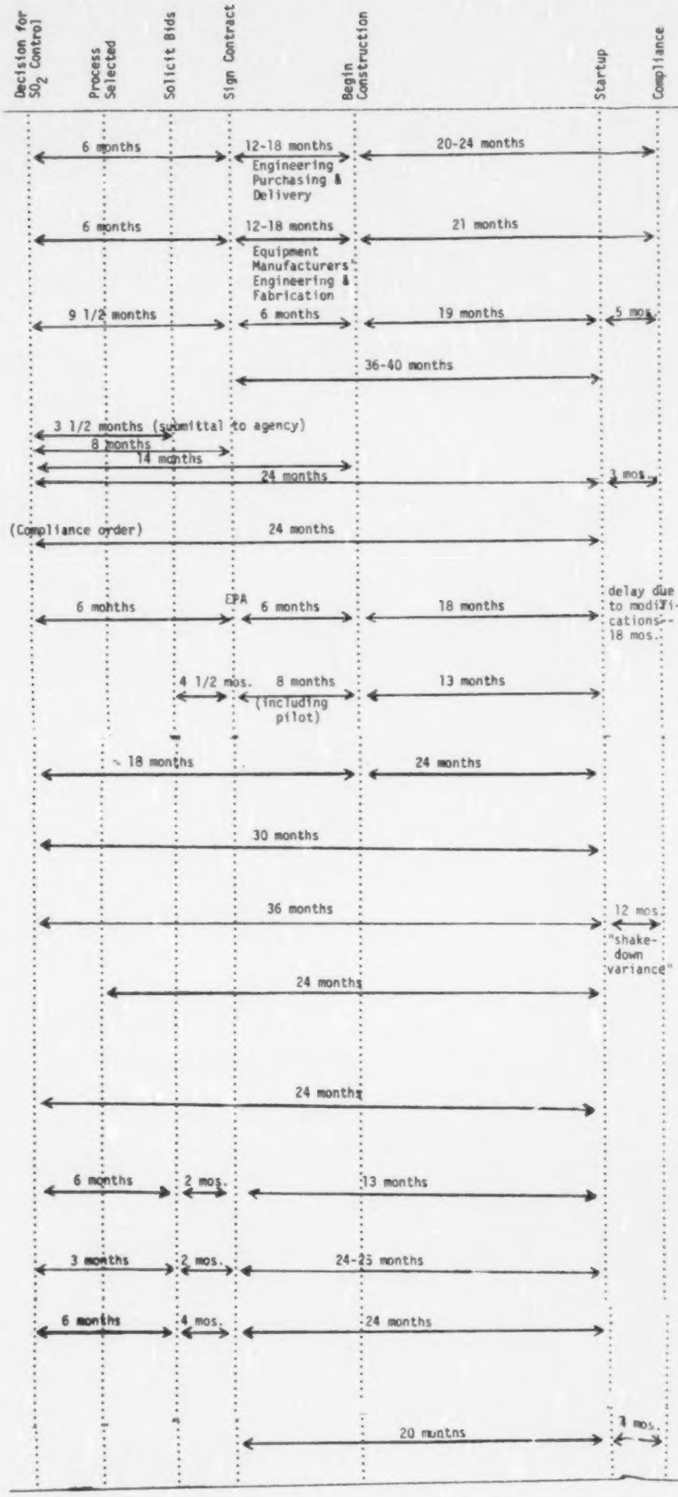
systems can be tied in to the generating facility. The actual time required to tie in an FGD system to a boiler unit is only a few weeks. However, because the boiler must be out of operation during tie in, timing would have to be planned carefully so that the overall generating system would still produce adequate power. For a utility company which must install FGD systems at several plants, the tie in operations at each plant would have to be properly sequenced.

These time frames assume that the utility will proceed to install a full scale FGD system with no piloting or experimentation. In those cases where a developmental program is required, completion of the full scale system could take 12 to 36 months longer depending upon the degree of experimentation. Piloting of a new system would require the greatest additional time.

The more typical "front-end modular" approach discussed at the hearing is the case where one FGD module is installed and operated for a few months before installation of the full FGD system. In such instances, the additional time is used to optimize operating parameters and possibly to investigate innovations in process. In many cases the modular approach is not necessary and installation of a full scale system can proceed directly through the usual steps of construction, tie in, shakedown, and compliance. However, in some situations, such as the installation of a new type of system, use of the modular approach could be appropriate. A reasonable schedule for installation of a full scale system via the modular approach will generally be from 41 to 54 months.

Table 9-1. TIME REQUIRED TO INSTALL FGD SYSTEMS



Reference	Total Time for Compliance	Type of Development	Notes
Estimate by George C. Kuhlman of Sargent & Lundy for NIPSCO. (p. 589 590)	38-48 months	Full scale large unit	Schedule requires all equipment on site before construction begins.
Estimate by Tor Korflat of Sargent & Lundy for PS of Indiana. (p. 712)	39-45 months	Full scale large unit	Schedule requires all equipment on site before construction begins.
Allowed under Pa. variance approval for West Penn Power. (p. 2929 - 2931)	39 1/2 months	Full scale large unit	
Stites of Research Cottrell. (p. 1330)			
Given by Gerstle of PEDCo. (p. 664 - 665)	27 months	Full scale large unit	Assuming 3-month startup.
Actual time for PEPCo. (p. 2472 - 2474)	Approx. 30 months	Full scale demonstration unit	Assuming 6-month startup.
Actual time as given by Illinois Power Company. (p. 1602 - 1604)	36 months[1,2]	New process	Delay due to major modification.
Actual time as given by Mr. Mayrose for LG & E. (p. 1202 - 1203).	Approx. 30 months	Full scale demonstration unit	Actual startup about 3 months.
Actual planned time for Philadelphia Electric Co. (p. 1928)	60 months[2] full compliance	New Process Demonstration unit	Characterized as long due to "developmental nature".
Estimate of P.S. of Colorado. (p. 3098)	36 months	Full scale medium-size unit	May be particulate only.
Allowed to Ohio Utilities in Alan Farkas testimony. (p. 1417 and 1421)	36 months[2]	Full scale large unit	
Actual at Lacygne. (p. 1459 - 1460)	Approx. 33 months	Full scale large unit	Does not include "shakedown". Described as crash program. Recommend 36 months.
Written submittal by Woods of Ariz. Public Service. Excessive overtime. Particulate only. (p. 1699)	Approx. 30 months	Full scale large unit	Crash program. Particulate only.
Actual time at Will County. "Crash program". (p. 2078 - 2081)	Approx. 27 months	Full scale medium-size unit	Described as crash program for difficult retrofit.
Universal Oil Products estimate. (p. 2598 - 2599)	Approx. 36 months	Full scale large unit	
Schedule as presented by Duquesne Light Company. (p. 1545 - 1547, p. 1578, p. 1595 - 1596 & submittal).	34 months[2] module 58 months total compliance	Pilot and modular approach. One year operation of module.	34 months is to particulate scrubbing only.
Estimate by Davy Power Gas. (p. 2469).	Approx. 30 months.	Full-scale large unit	

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[1] Delay neglected due to non-recurring modification due to natural gas cutoff.

[2] Does not include "shakedown" during which time the unit may either cause boiler outages or violations.

During the course of the hearing, it became apparent that the ability of vendors of flue gas desulfurization (FGD) systems to install such systems could be a constraint to timely compliance with sulfur oxide emission limitations. Two predictions of overall vendor capacity were dicussed at the hearing: the Sulfur Oxide Control Technology Assessment Panel (SOCTAP) final report on Projected Utilization of Stack Gas Cleaning Systems by Steam-Electric Plants[1] and the Industrial Gas Cleaning Institute (IGCI) survey and analysis.[2] In addition, some individual vendors discussed their capacity for future installation of scrubbers. Each prediction given was based on certain assumptions.

It is important to examine some of tne key assumptions of each of the reports. SOCTAP evaluated 15 sulfur oxide control system vendors and projected that three or four could expand rapidly and that another three or four could expand at a slower rate. The remaining seven to nine vendors were considered to have unproven abilities and the panel felt that they would not play an important role until the late 1970's. SOCTAP also predicted that some new vendors would enter the market. SOCTAP did use two "choke points" in their projections: one, the ability of the vendors to sell their wares; and two, the ability of vendors to bring systems on-line smoothly while continuing to take on new projects. The potential for delays due to shortages in critical materials and engineering and skilled construction manpower was considered in their projections.

The IGCI conducted a survey of 24 vendors (including nonmembers), asking for an assessment of each company's unconstrained capacity to provide commercial sulfur oxide control systems. The IGCI analysis essentially assumed that each vendor polled would provide 100 percent of predicted capacity. This assumption may hold in the 1978-1980 period as more vendors gain experience and the most promising systems are licensed, but it is questionable for the 1974-1977 period because few vendors have proven capabilities to supply scrubbing systems. In addition, IGCI stated that possible material and labor shortages were not considered in their estimates.

Mr. Watt of Davy Powergas Co. stated that his company is handling a current load of four or five projects[3] and Mr. Singer of C.E. testified that six projects are currently in his shop.[4] Combustion Engineering projected that it would be able to handle nine additional projects by 1978. The major problem now faced by the SO_x control equipment vendors, as stated by IGCI, is that "no market exists."

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[1] Final Report: Projected Utilization of Stack Gas Cleaning Systems by Steam-Electric Plants. Sulfur Oxide Control Technology Assessment Panel (SOCTAP) Report to the Federal Interagency Committee. U.S.E.P.A., Research Triangle Park, N.C. Publication No. APTD-1569. April, 1973.

[2] Transcript, Sidney R. Orem, Industrial Gas Cleaning Institute, p. 1839.

[3] Testimony, Stewart Watt, Davy Powergas, p. 2470.

[4] Testimony, Joe Singer, Combustion Engineering, p. 1292.

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Figure 10-1 shows the cumulative need and cumulative vendor capacity estimates made by SOCTAP and by IGCI in megawatts of installed capacity versus time. Also shown is the curve which the hearing panel feels best estimates the ability of vendors to install scrubbing systems.

Because orders must be placed soon for scrubbers to be installed in 1976-1977, vendor capacity through that period is largely limited by existing experience and capability of vendors. For this reason, the panel believes that actual experience during this period will likely follow the more conservative SOCTAP estimate. Capacity in the later 1970's, however, will be dependent on the extent to which additional vendors gain experience and the extent to which all vendors increase their capacities. This increase will depend largely upon the market the vendors envision. Assuming that States and EPA push ahead vigorously with sulfur oxide compliance requirements, the panel believes that actual experience during the later 1970's will most likely approach the IGCI estimates.

It is important to stress that future vendor capacity will depend upon expected demand. At the moment, capacity exceeds demand. In addition, many vendors can gain experience only through the installation of scrubbers. The panel believes that its estimate of vendor capacity will not be achieved unless firm compliance schedules are established and vigorously enforced.

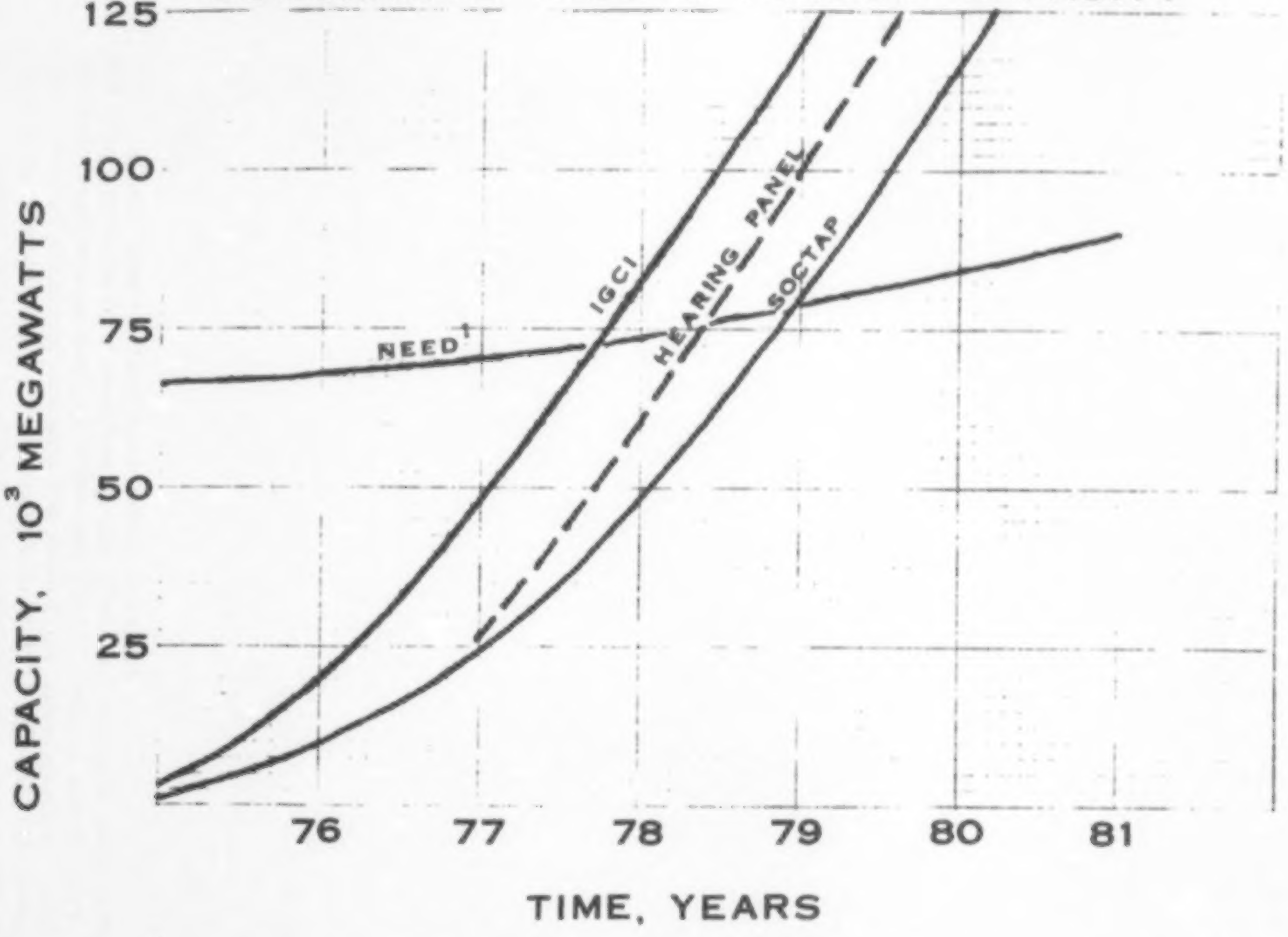
Figure 10-1 also shows EPA's best estimate of FGD needs (discussed in the Background section of this report) for existing coal-fired power plants impacting primary standards and for new coal-fired plants. On the basis of this estimate of FGD requirements and the hearing panel's estimate of vendor capacity, it is clear that the timetables of many State implementation plans (compliance by mid-1975) will not be met.

The date by which all the requirements will be met is difficult to estimate. Although Figure 10-1 leads to the conclusion that the last scrubber needed by coal-fired power plants to meet primary ambient air quality standards can be installed sometime in 1978, it must be noted that scrubber needs for oil-fired power plants and for such other sources as large industrial boilers were not included in the analysis.

It is also important that Figure 10-1 does not estimate all FGD needs for existing State implementation plans since these plans require controls beyond those needed for attainment of primary standards. Although requirements related to attainment of primary standards should receive priority over other requirements, the other requirements must also be met and will add to the demand for FGD systems, particularly in the later 1970's.

FIGURE 10-1

CUMULATIVE NEED & VENDOR CAPACITY



[1] Includes new and existing coal-fired plants requiring controls to achieve primary standards or new source performance standards.

Vendor capacity is expected to constrain the rate at which needed FGD systems can be installed; however, it is more important that capacity currently exceeds the demand for these systems. Commitments must now be made to order and install needed FGD systems and this effort should continue at the quickest possible rate; that is, at a rate commensurate with vendor capacity.

APPENDIX A - Description and Summary of Important FGD Processes

A. Sulfur Product Throwaway Systems

1. Lime and Limestone Flue Gas Desulfurization Processes - Throwaway

Process

Several methods have been developed for the use of limestone and lime slurries in a wet scrubbing process. The major variations are as follows: (See Figure A-1)

(1) use of limestone ($CaCO_3$) added to the scrubber circuit

(2) use of hydrated lime ($Ca(OH)_2$) added to the scrubber circuit

(3) use of limestone injected in the boiler affecting calcination to lime with subsequent lime slurry scrubbing.

In all three process modes, a slip stream subjected to a dewatering operation consisting of reaction products, flyash, and unreacted alkali is discharged as waste to either a disposal pond or landfill site.

The overall reactions for limestone and lime scrubbing can be represented by reactions (1) and (2) respectively:

(1) $CaCO_3 + SO_2 + 1/2H_2O \rightarrow CaSO_3.1/2H_2O + CO_2$

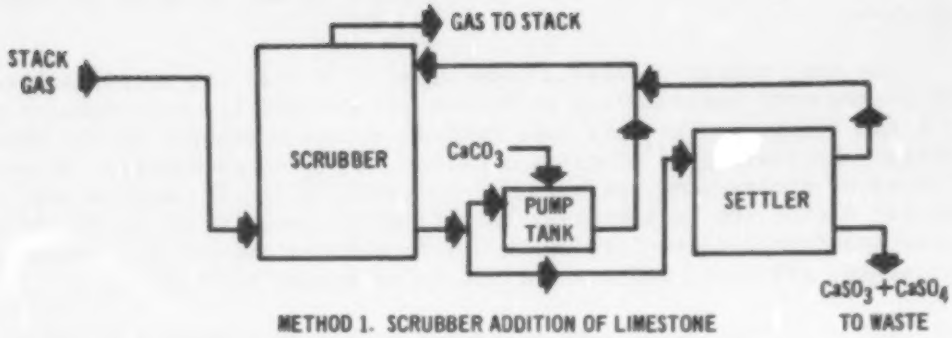
(2) $Ca(OH)_2 + SO_2 \rightarrow CaSO_3.1/2H_2O + 1/2H_2O$

History and Experience

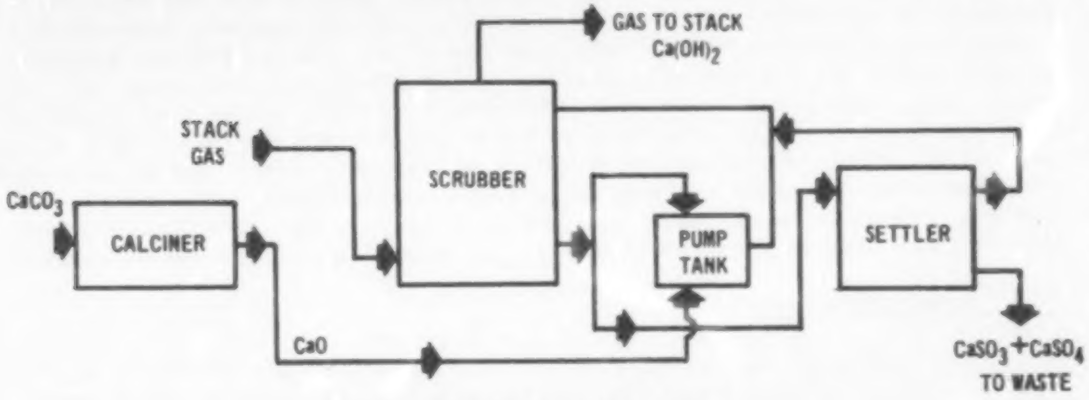
There has been a considerable amount of bench model, pilot plant, and full scale activity since the early 1930's. Over the last 5 years developmental activities have been particularly intense and 31 full scale commercial systems have been ordered in the U. S. since 1968, of which 7 have started-up and have a backlog of operating experience.

The boiler injection plus wet scrubbing process has been extensively tested on a commercial scale by Combustion Engineering, Inc., (C.E.) since 1968. After 4 years of intermittent operation filled with numerous technical difficulties, C. E. no longer offers this process; C.E. favors the lime/limestone tail-end scrubbing process.

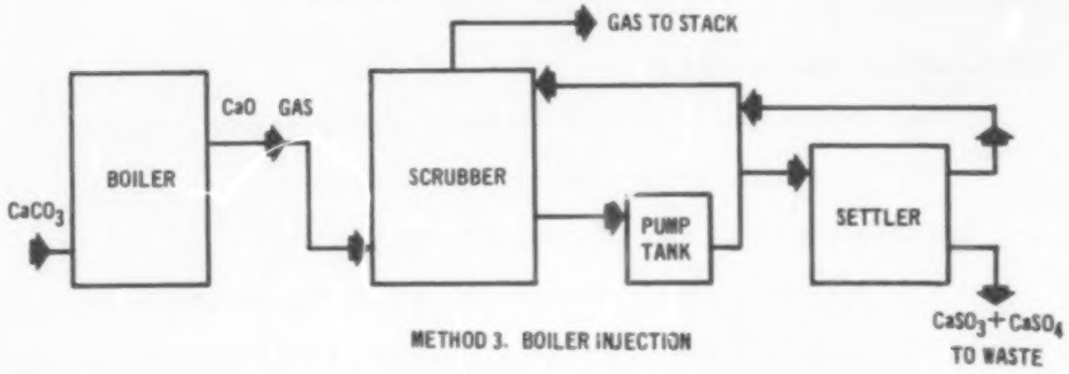
The first full scale installation in this country that uses limestone introduced into the scrubbing circuit is the 175 megawatt Commonwealth Edison Will County Station - Unit No. 1. This unit was started up in February 1972, and has operated intermittently since then, achieving SO_2 removal efficiencies in the range of 75 to 85 percent. The major problems experienced to date have involved demister pluggage by a soft, mud-like substance, system reliability caused by mechanical problems, and finding an economic means for disposal of waste sludge. A great deal has been learned in the past year at the Will County Unit concerning practical operating problems with limestone scrubbing. None of the problems encountered at this unit appear to be insurmountable.


GAS TO STACK
STACK GAS
SCRUBBER
$CaCO_3$
PUMP TANK
SETTLER
$CaSO_3 + CaSO_4$ TO WASTE

METHOD 1. SCRUBBER ADDITION OF LIMESTONE


GAS TO STACK
$Ca(OH)_2$
STACK GAS
$CaCO_3$
CALCINER
SCRUBBER
PUMP TANK
SETTLER
CaO
$CaSO_3 + CaSO_4$ TO WASTE

METHOD 2. SCRUBBER ADDITION OF LIME


GAS TO STACK
CaO GAS
$CaCO_3$
BOILER
SCRUBBER
PUMP TANK
SETTLER
$CaSO_3 + CaSO_4$ TO WASTE

METHOD 3. BOILER INJECTION

Figure A-1. Major process variations for use of lime or limestone for removal of SO_2 from stack gases.

Additional valuable information concerning operation of lime/limestone scrubbing processes is being gathered at the versatile EPA prototype test facility at the TVA Shawnee Steam Plant. The 30 megawatt facility includes three types of 10 megawatt (equivalent) scrubbers (venturi, TCA, and marble-bed), extensive process instrumentation, and sophisticated data acquisition and handling systems. Tests to date have identified test conditions which have led to reliable operation during tests up to 1 month in duration.

The most recent successful operation of a lime wet scrubbing process is the 70 megawatt installation at Louisville Gas and Electric Company's Paddy's Run Station. The unit uses carbide sludge ($Ca(OH)_2$) as the alkaline absorbent. No scaling or plugging problems have been encountered in over 1000 hours of closed-loop operation since April 1972. The system has demonstrated near 100 percent availability while removing 85 to 95 percent of the flue gas from boilers fired with 3.5 to 4.0 percent sulfur. Waste sludge is thickened, filtered, and disposed of as untreated landfill.

The most successful lime scrubbing system is Chemico's Mitsui Aluminum Company's facility. This 156 megawatt power plant has been retrofitted with two Chemico dual-stage venturi scrubbing systems, each capable of handling 75 percent of the full load gas flow. The system has demonstrated reliable, trouble-free operation since being put on-stream in March 1972. The plant is presently burning 2 percent sulfur coal (1800 to 2200 ppm inlet SO_2) and achieving 80 to 85 percent SO_2 removal from the flue gas using carbide sludge as the alkaline absorbent. Since coming on-stream, the system has operated at near 100 percent availability. The absence of scaling difficulties has been attributed to operational data developed by Mitsui in extensive pilot plant tests (in Japan) and to precise pH control.

SO2 Removal Efficiency

A survey of the seven companies having experience in full-scale tail-end wet scrubbing shows that most companies will provide SO_2 removal guarantees varying from 70 to 90 percent, or as required to meet EPA standards.

Advantages and Disadvantages

The advantages of lime and limestone systems are as follows:

(1) relatively low capital and operating costs

(2) potentially high SO_2 removal efficiencies

(3) ability to simultaneously remove both SO_2 and particulates

(4) most fully characterized of flue gas desulfurization systems

The disadvantages are:

(1) requirement to dispose of large quantities of waste sludge in an environmentally acceptable manner

(2) If not carefully designed, a tendency toward chemical scaling, plugging, and erosion problems.

Performance and Reliability Summary

Operating experience at the Mitsui, Shawnee, and Louisville Gas and Electric scrubbers indicates that lime/limestone scrubbers which have the alkali added to the scrubber circuit can be made to operate reliably. The Mitsui unit in particular has demonstrated reliable operation of this technology over 1 1/2 years.

However, experience at other facilities indicates that reliability can be a problem if the systems are not carefully designed and operated. Also, the boiler injection mode has proven to be a troublesome configuration (Union Electric and Kansas City Power & Light units) prone to serious operating problems.

2. Double Alkali Flue Gas Desulfurization Process - Throwaway

Process (See Figure A-2)

The many double alkali process variations involve the scrubbing of flue gases with a clear liquor containing dissolved sodium or ammonium salts, followed by treatment of the depleted liquor with lime or limestone in a reaction producing a throwaway sludge for disposal and alkali liquor for scrubbing. Typical reactions occuring in the scrubber and reaction tank, respectively, are as follows for a sodium-based system:

(1) $Na_2SO_3 + SO_2 + H_2 \longrightarrow 2NaHSO_3$

(2) $2NaHSO_3 + Ca(OH)_2 \longrightarrow Na_2SO_3 + 3/2H_2O + CaSO_3.1/2H_2O$

History and Experience

In the United States primary developmental attention has been placed on sodium-based double alkali systems using lime for regeneration. Important pilot plant work has been performed by General Motors, FMC Corp., Envirotech, A. D. Little/Combustion Equipment Associates, and Chemico.

Southern Co. is planning to test a double alkali system on equivalent 20 megawatts of coal combustion flue gas at the Sholz plant operated by Gulf Power Co. in Florida.

Intensive development of double alkali systems has been performed in Japan, with limestone used as the input alkali and gypsum produced as a saleable product. Showa Denko has recently started-up a 156 megawatt system on an oil-fired power plant. Two additional 150 megawatt units treating oil-fired boilers using Kawasaki/Kureha technology are under construction and will start-up in 1974.

SO_2 Removal Efficiency

Based on pilot scale results to date, SO_2 removal efficiencies between 90 and 99 percent are achievable at reasonable costs.

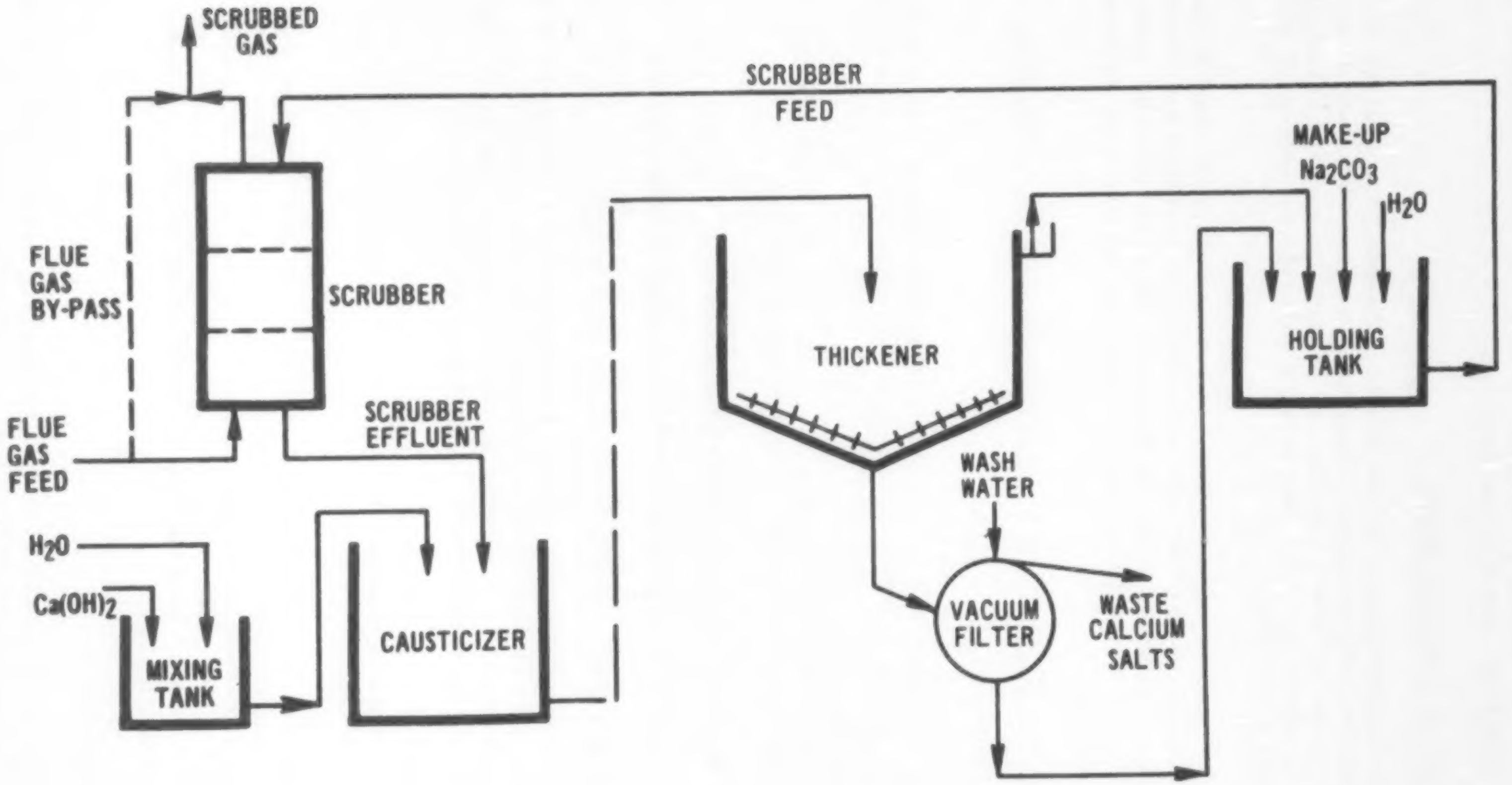

SCRUBBED GAS
SCRUBBER FEED
MAKE-UP
Na_2CO_3
H_2O
FLUE GAS BY-PASS
SCRUBBER
THICKENER
HOLDING TANK
SCRUBBER EFFLUENT
FLUE GAS FEED
WASH WATER
H_2O
$Ca(OH)_2$
MIXING TANK
CAUSTICIZER
VACUUM FILTER
WASTE CALCIUM SALTS

Figure A-2. Double alkali process variation - sodium scrubbing with lime regeneration.

Advantages and Disadvantages

The advantages of double alkali systems include:

(1) relatively low capital and operating costs

(2) very high SO_2 removal efficiencies can be obtained

(3) use of clear solution scrubbing minimizes solids buildup and erosion problems offering potential for high reliability

(4) ability to simultaneously remove SO_2 and particulates

Disadvantages include:

(1) Requirement to dispose of large quantities of waste sludge in an environmentally acceptable manner

(2) Design complexities necessary to deal with the following problems:

  (a) necessity to prevent excessive purge of Na_2SO_4 produced as a result of oxidation (Na_2SO_4 is difficult to regenerate)

  (b) necessity to avoid scrubbing with clear liquor saturated with calcium sulfate which could lead to scaling problems

Performance and Reliability Summary

Based on pilot scale operating experience at General Motors, FMC Corp., Envirotech, A. D. Little in the United States, and Kureha and Showa Denko in Japan, double alkali systems offer potentially high SO_2 removal ($>$90 percent) with high reliability.

B. Saleable Product FGD Systems

1. Magnesium Oxide SO_2 Scrubbing Process - Saleable Product

Process (See Figure A-3)

The Chemico/Basic MgO process utilizes an aqueous slurry of magnesium oxide, magnesium sulfite and magnesium sulfate to scrub SO_2 from flue gas streams. The major reaction involves the formation of additional magnesium sulfite through combination of SO_2 and magnesium oxide. Magnesium sulfite removed from the scrubber loop is dried and subsequently calcined to drive off $SO2$ and regenerate active MgO for return to the scrubber loop. The regeneration can be accomplished either at the power plant site or at some remote location since the magnesium sulfite and magnesium oxide are stable solids capable of being shipped. The SO_2 generated in the calcining operation can be converted to high grade sulfuric acid or to elemental sulfur by provision of the appropriate equipment.

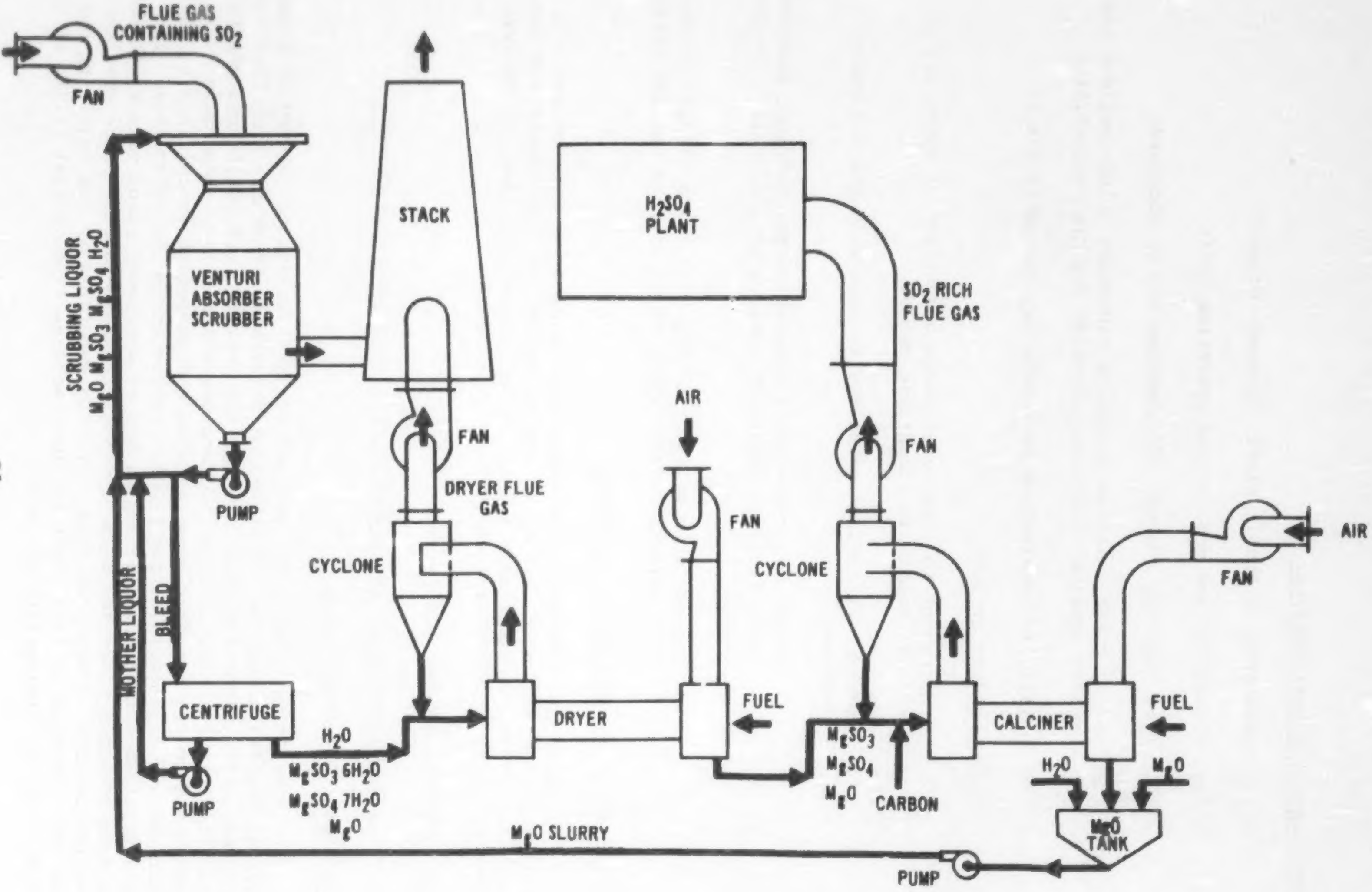

FLUE GAS CONTAINING SO_2
FAN
SCRUBBING LIQUOR MgO $MgSO_3$ $MgSO_4$ H_2O
VENTURI ABSORBER SCRUBBER
STACK
H_2SO_4 PLANT
SO_2 RICH FLUE GAS
PUMP
FAN
DRYER FLUE GAS
AIR
FAN
FAN
CYCLONE
CYCLONE
AIR
FAN
MOTHER LIQUOR
BLEED
CENTRIFUGE
H_2O
$MgSO_3$ $6H_2O$
$MgSO_4$ $7H_2O$
MgO
PUMP
DRYER
FUEL
$MgSO_3$
$MgSO_4$
MgO
CARBON
CALCINER
FUEL
H_2O
MgO
MgO TANK
MgO SLURRY
PUMP

Figure A-3. MgO slurry process - for flue gas free of particulate matter.

History and Experience

In June of 1970 EPA entered into an agreement with Chemico/Basic, Boston Edison Company and Essex Chemical Company for construction and operation of the Chemico/Basic Magnesia Slurry Process on the No. 6 boiler at Boston Edison's Mystic Station in Everett, Massachusetts. The installation on this 155 megawatt oil-fired boiler was completed in May of 1972. The year following completion of the system has been devoted to equipment modifications and investigations directed toward solving numerous operational problems which developed. Most of the problems which were encountered were of a materials-handling nature resulting from the character of the solids generated in the scrubber loop. The fact that most of these problems have been satisfactorily solved is demonstrated by the 85 to 90 percent availability factor for June and July of this year. Some equipment modifications are continuing to improve operability.

An additional MgO system has recently been started in September of this year at Potomac Electric Power Co.'s Dickerson Station. This unit will handle one-half the flue gas from a 195 megawatt coal-fired unit. The system is designed to accommodate flue gas from the burning of 3.0 percent sulfur coal. Very early results are encouraging. An additional coal-fired application designed and engineered by United Engineers & Constructors is nearing completion at Philadelphia Electric's Eddystone Station. This unit, which is due for a December 1973 startup, will handle the equivalent of 120 megawatts with 2.5 percent sulfur coal fuel.

Advantages and Disadvantages

The major advantages to the MgO process are summarized as follows:

(1) sulfur can be recovered as high grade acid or elemental sulfur depending upon equipment provided for regeneration

(2) regeneration can be accomplished at a location quite distant from the power plant (for instance, at an existing sulfuric acid plant) thus permitting the use of a central regeneration facility servicing several flue gas cleaning locations.

(3) by maintaining adequate inventories of MgO, extended outages of the regeneration facility can be tolerated without interruption of the pollution control facility.

(4) process reliability has benefitted from the modifications and investigations at the Boston Edison site and will continue to improve as the two additional systems (Potomac and Philadelphia) become fully operational in the near future.

The major disadvantage of the process is the lack of reliable long term operating experience and a lack of experience with coal fired power plants.

SO_2 Removal Efficiency

The MgO process is capable of achieving 90 percent SO_2 removal over a wide range of inlet SO_2 concentrations.

Performance and Reliability

The experience to date at Boston Edison has established the capability of the process to consistently achieve 90 percent SO_2 removal. Also, the high turndown capability and the reliable operation of the venturi scrubber configuration used at Boston Edison have both been established. The reliability of the entire MgO process has not as yet been established through long term operation; however, the on-stream time at Boston Edison has improved with the various modifications to achieve an 85 to 90 percent availability for June and July 1973. Modifications to improve system reliability are continuing.

2. Wellman-Lord Flue Gas Desulfurization Process - Saleable Product

Process (See Figure A-4)

The Wellman-Lord (W-L) SO_2 Recovery Process utilizes a sodium sulfite-sodium bisulfite solution to absorb SO_2 from flue gas. The spent absorbent, rich in bisulfite, is processed in a steam-heated evaporator, regenerating active sodium sulfite crystals and producing a stream of SO_2 for further processing. The process, depicted in simplest form is:

- Absorption

$$SO_2 + Na_2SO_3 + H_2O \rightarrow 2NaHSO_3$$

- Regeneration

$$2NaHSO_3 \xrightarrow[\text{heat}]{} Na_2SO_3 \downarrow + SO_2 \uparrow + H_2O \uparrow$$

Inactive sodium sulfate is formed by three mechanisms: SO_3 absorption, disproportionation, and sulfite oxidation. Sodium sulfate must be purged from the system in order to maintain adequate levels of active sulfite in the absorber/evaporator loop.

History and Experience

Patents for the W-L Process were filled in 1966 and patent rights are currently held by Davy Powergas, Inc., Lakeland, Fla. Two Japanese firms are licensed to market the system. There are currently seven operating plants in the U. S. and Japan including two oil-fired boiler applications. Additionally, more than ten systems are on order, including five more boiler applications. The earliest operating W-L System is the sulfuric acid plant application at Paulsboro, New Jersey, which has been operating since July of 1970. The earliest boiler application is the industrial boiler (oil-fired) at Japan Synthetic Rubber Co., Chiba, Japan. This unit, equivalent to 75 megawatts, has been operating successfully since August of 1971 and has an excellent on-stream factor of 97 percent since that time. It is worthy of note that both Japan Synthetic Rubber (JSR) and Olin Corporation (owner of the Paulsboro system) have ordered additional systems, thus attesting to the satisfactory performance of the W-L System. Standard Oil of California purchased a W-L System for Claus Plant tailgas cleanup which was started in June

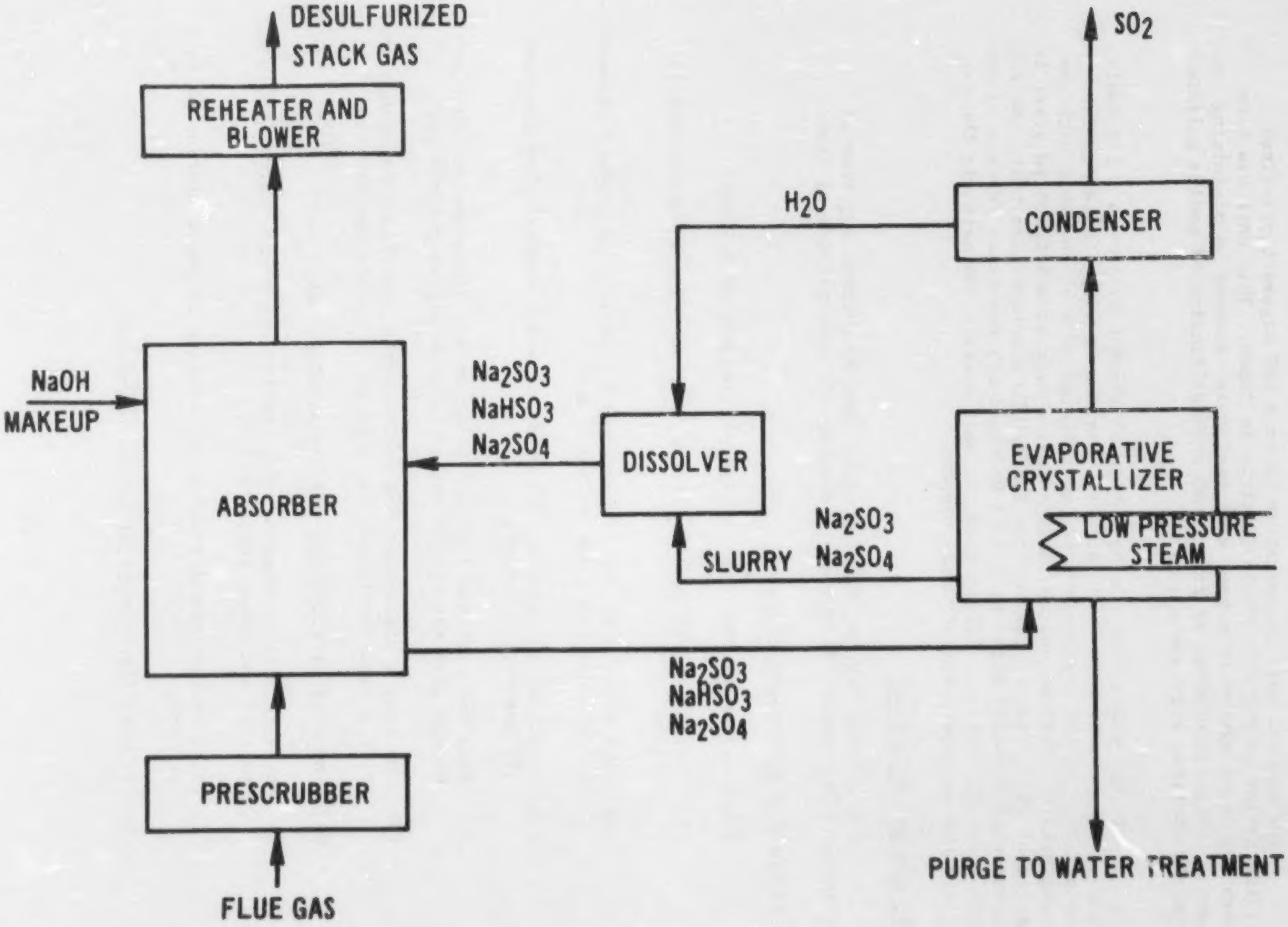

DESULFURIZED STACK GAS
REHEATER AND BLOWER
NaOH MAKEUP
ABSORBER
PRESCRUBBER
FLUE GAS
Na_2SO_3
$NaHSO_3$
Na_2SO_4
DISSOLVER
H_2O
SLURRY
Na_2SO_3
Na_2SO_4
SO$_2$
CONDENSER
EVAPORATIVE CRYSTALLIZER
LOW PRESSURE STEAM
Na_2SO_3
$NaHSO_3$
Na_2SO_4
PURGE TO WATER TREATMENT

Figure A-4. Wellman-Lord process schematic.

of 1972. As a result of the performance of the unit, Standard has ordered three additional W-L Systems for other locations.

The largest unit in operation is on a 220-megawatt oil-fired utility boiler operated by Chubu Electric in Japan. This unit has been operating since May of this year with particular success in minimizing the quantity of sulfate purge by fractional crystallization of sodium sulfate from the absorber effluent liquor.

EPA has undertaken demonstration of the W-L System on a 115 coal-fired boiler at NIPSCO's D. H. Mitchell Station in Gary, Indiana. The capital cost of the system is being cost-shared on a 50-50 basis with the using utility, NIPSCO, and the demonstration year is scheduled to start in Spring of 1975. In the case of the EPA/NIPSCO demonstration unit, the W-L System will be mated with the Allied Chemical SO_2 Reduction Process to produce elemental sulfur. Allied Chemical will operate and maintain the W-L Allied System under contract with NIPSCO.

SO_2 Removal Efficiency

W-L Systems have obtained greater than 90 percent SO_2 removal efficiency for commercial systems operating for long periods of time.

Advantages and Disadvantages

The W L process has several major advantages as follows:

(1) simplicity and reliability of the various unit operations involved

(2) when mated with the proper process, ability to produce elemental sulfur, or high grade sulfuric acid

(3) potential to achieve high efficiency SO_2 removal when required (95 percent or better)

(4) provided with surge capacity before and after the absorber to handle flue gas surges and to enhance system reliability

(5) the many applications and considerable operating experience provide a high confidence for success in future applications

Major process difficulties and disadvantages are:

(1) need to sell or dispose of a quantity of purge solids (sodium sulfate and other sodium salts)

(2) high energy demand results in derating of power station (3 to 6 percent)

(3) no coal-fired applications in operation

Performance and Reliability Summary

Operating W-L Systems have consistently achieved SO_2 removal efficiencies in excess of 90 percent for a wide range of SO_2 inlet concentrations. The most significant development efforts to date have been in the areas of reduced capital costs and minimization of purge requirement. As a result of process modifications which have now been proven in various operating systems, purge requirements of 5 percent or less of inlet sulfur can be anticipated.

Both the inherent high reliability of the equipment involved in the W-L process and the actual operating experience (97 percent on-stream factor over a 2 year period at the JSR boiler installation) point to an availability in excess of 95 percent. The high system reliability would be enhanced in large scale systems due to the opportunity for greater use of equipment spares and partial system operation as a result of multi-train configuration. The current practice of providing absorbent surge capacity permits short-term shutdown of the regeneration process without interruption of the scrubbing capability.

3. Catox Flue Gas Desulfurization Process - Saleable Product

Process (See Figure A-5)

The Monsanto Cat-Ox process utilizes catalytic oxidation to convert most of the SO_2 present in the flue gas stream to SO_3 for subsequent removal by an acid absorbing tower (followed by a fiber-packed mist eliminator to remove H_2SO_4 mist). For retrofit or "reheat" applications, the flue gases emerging from the boiler are passed through a high efficiency (99.6 percent precipitator)and then heated ("reheated") to 850°F as preparation for the catalytic oxidation step. The strength of acid produced in the absorbing tower is ≈80 percent, which is primarily suitable for use in fertilizer production.

History and Experience

The Cat-Ox process was piloted on a 15 megawatt scale for 2 years commencing in August of 1967. Based on the successful pilot operation, agreement was reached in June 1970 between EPA, Illinois Power (IP), and Monsanto to install and operate a demonstration Cat-Ox system on a 110 megawatt coal-fired boiler at IP's Wood River Station at East Alton, Illinois. Construction of the system was completed in July of 1972 and after a considerable debugging period, the system was acceptance-tested in July 1973. However, because of the present lack of availability of natural gas, the reheat burners must now be modified to provide the capability for 100 percent firing on fuel oil. This has occasioned another delay which will preclude commencement of the year-long demonstration program until approximately April 1974.

SO_2 Removal Efficiency

During the acceptance test, the Illinois Power system achieved the emission control guarantees of 85 percent SO_2 removal and 99 percent

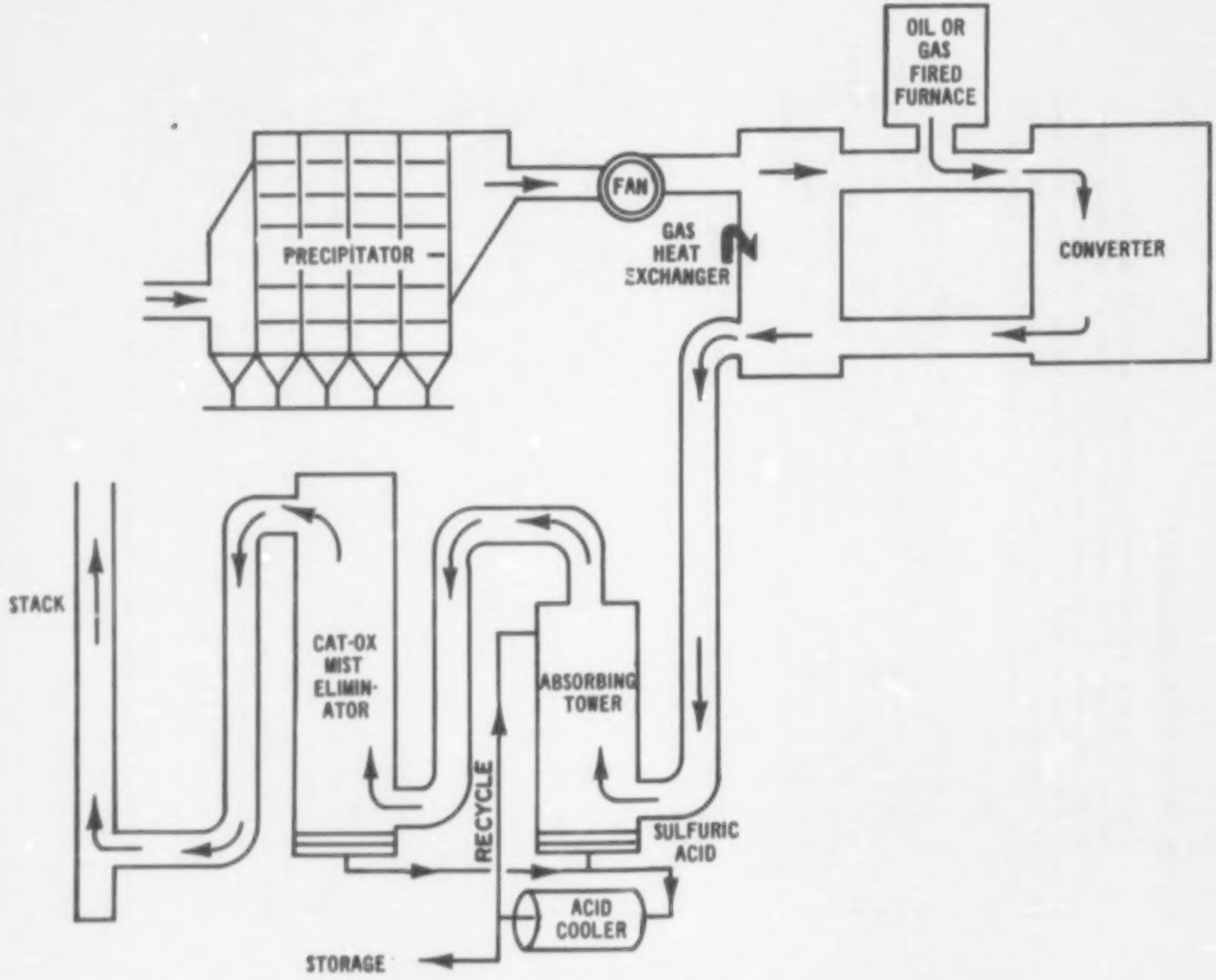

OIL OR GAS FIRED FURNACE
PRECIPITATOR
FAN
GAS HEAT EXCHANGER
CONVERTER
STACK
CAT-OX MIST ELIMIN-ATOR
ABSORBING TOWER
RECYCLE
SULFURIC ACID
ACID COOLER
STORAGE

Figure A-5. Reheat Cat-Ox process.

particulate removal. Removal efficiencies of greater than 90 percent are achievable with this technology for many applications.

Advantages and Disadvantages

The Cat-Ox Process advantages are as follows:

(1) Generates a product, which, in certain limited locations, can be disposed of by sale

(2) operating costs are relatively low

(3) achieves consistent 85 percent or better SO_2 removal over a wide range of SO_2 input concentrations

The major process difficulties and disadvantages are:

(1) Cat-Ox must be used near an appropriate acid user and dilute acid can be difficult to market in large quantities in some locations

(2) capital costs are high

(3) reliability and maintenance costs are not currently established due to a lack of operating experience

Performance and Reliability Summary

Work to date at the Wood River demonstration site has established the capability of the system to achieve 85 percent SO_2 removal; however, no information is available regarding system reliability or any possible performance degradation as a function of operating time. It should be noted, however, that the process and equipment are similar to the standard contact acid process and that major reliability uncertainties associated with the process center around the ability of the precipitator to provide adequate particulate removal to protect the catalyst bed.

APPENDIX B - Summary of Operational Experience with Full Scale FGD Units in the United States & Japan

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A. Operational Experience on U. S. Installations

Process: Boiler Injection of Limestone Followed by Wet Scrubbing
Process Supplier: Combustion Engineering
Constructor: Combustion Engineering
System Location: Union Electric Co., Meramec unit 2, St. Louis, Mo.
Start-Up Date: September 1968

SYSTEM DESCRIPTION AND HISTORY OF OPERATION

This 140 MW unit, the first full-scale utility SO_2 control system in this country, was officially shut down and abandoned in December 1971 approximately three years after its inception. This system consisted of two parallel single-stage marble bed absorbers equipped with demisters and reheaters. It was operated with some clarified liquor recycle.

The reason for abandonment was massive plugging and scaling in the entire boiler and SO_2 removal system. This recurrent problem barred the company from keeping the generating unit going for long periods. It has been said, however, that the up and down operation of the boiler necessitated by scrubber problems, due to the fact that no provisions for gas by-pass had been made, may have compounded the problems by causing moisture to combine with powdery deposits on the boiler tubes to form concrete-like deposits during periods of boiler shutdown. The implication is that boiler plugging might have been at least minimized by equipping the scrubber system with a bypass, thus allowing the boiler to operate independently of the scrubber, and less intermittently.

Process: Limestone injection in boiler with throwaway product.
Process Supplier: Combustion Engineering.
Constructor: Combustion Engineering.
System Location: Kansas Power and Light, Lawrence, Kansas, Units No. 4 & 5.
Startup Date: December 1968 and November 1971.

The 125 mw Unit No. 4, started up in December of 1968, was one of the first attempts to design a full size SO_2 scrubber. The limestone injection method was used. Multiple problems occurred during early stages of operation including corrosion, plugging of lines, and problems with reheaters and demisters. These problems did not include scaling. During the first four months of 1971, modifications in the original design enabled operation with some reliability.

When the scrubbers for the much larger 420 mw unit No. 5 started up in November 1971, the pond which was common to both units became overloaded and scaling occurred. Modifications in the design have been made that enable these chemical problems to be reduced but mechanical problems remain. At the present time, the modular arrangement enables the scrubbers to be cleaned without necessitating shutdown of the boiler.

The experiences at Lawrence have proved invaluable in making changes for later Combustion Engineering units such as the successful Paddy's Run plant. The Lawrence Station is, however, set in much of its design as a boiler injection system and in the closeness of the demisters to the absorbing bed. It, therefore, cannot fully benefit from the knowledge that has come from the operation of it and other systems.

Kansas Power and Light is able to operate a limestone SO_2 scrubbing system with significant SO_2 removal and some reliability while serving a large utility generating plant. This is a milestone in the development of SO_2 control technology.

Process: Limestone Scrubbing with Throwaway Product
Process Supplier: Babcock & Wilcox
Constructor: Babcock & Wilcox
System Location: Commonwealth Edison Co., Will County Station No. 1,
Romeoville, Ill., near Chicago
Start-Up Date: February 1972

SYSTEM DESCRIPTION AND HISTORY OF OPERATION:

Will County Unit 1 with scrubber on line, has a net power output of 156 MW. The system consists of two identical parallel wet limestone scrubbing trains, each consisting of a venturi for particulate removal, followed in series by a turbulent contact absorber (TCA) for SO_2 absorption. Each absorber and scrubber is equipped with its own recirculation tank. Spent slurry is bled to a clarifier which produces liquor for recycle via a 5 acre pond and a thickened sludge (underflow) which is pumped to a ready mix concrete truck where additives are mixed with the sludge in an attempt to make the sludge acceptable as landfill.

Since February 1972, the SO_x control systems have operated intermittently. Generally, SO_x removal efficiencies in the 80-90% range are attainable during periods of operation. Chemistry is not considered to be a problem with the system. Problems which have been responsible for shutdown of the system can be classified as mechanical, and were not all attributable to the SO_x control system. Some of the problems attributed to the limestone SO_x control system are: (1) demister and reheater pluggage; (2) wearing and plugging of spray nozzles; (3) reheater vibration and stress corrosion cracking; (4) plugging of slurry lines; (5) "sulfite blinding" of limestone and (6) scaling. Some of the other reasons cited for system outage are: (1) expansion joint failure; (2) inspection; (3) boiler outage; (4) motor failure; (5) contractor and operator errors; (6) fan trip; (7) water loss to pump glands; (8) fan damper operation; (9) leaks in slurry lines; (10) limestone supply and (11) booster fan vibration.

Solutions to almost all of the problems do not require development of new technology. Methods of controlling all of the problems specific to limestone wet scrubbing except for the reheater problems, have been used with some degree of success at Will County. Installation of inconel alloy reheater tubes is expected to solve the reheater stress corrosion cracking problem. Plugging is avoided by maintaining adequate flow of slurry. Scaling is controlled by circulation of high solids slurries and using adequate liquid/gas ratios. Demister pluggage is minimized by good demister wash techniques. Wear of nozzles is controlled by proper selection of materials of construction.

Between February and December 1972, the two SO_x control trains have accumulated in excess of 1400 and 1200 hours of operation respectively. During the outage periods many improvements and repairs were made. One of the trains has been shut down since April 1973 and presently is being cannibalized to support the other. Commonwealth Edison is attempting to iron out the problems with one train before attempting to operate both simultaneously.

Process: Magnesium Oxide Scrubbing with Thermal Regeneration
Process Supplier: Chemical Construction Corporation (Chemico)
Constructor: Chemical Construction Corporation
System Location: Boston Edison's Mystic Station
Everett, Massachusetts
Startup Date: April 1972

System Description and Operational History:

The MgO system which has been applied to the 150 MW oil-fired boiler at Boston Edison's Mystic Station utilizes a venturi scrubber to contact the magnesium oxide-magnesium sulfite slurry with boiler flue gases. The solids removed from the scrubber, rich in magnesium sulfite, are dried in a direct fired rotary dryer. The dried solids are shipped by truck to the Essex Chemical Company contact acid plant in Rumford, Rhode Island where the magnesium sulfite is calcined. The SO_2 produced by the calcining operation is converted to high grade sulfuric acid and the MgO produced is shipped back to Mystic Station for reuse in the absorber.

In April 1972, the shakedown period began for the Mag-Ox scrubbing system. The venturi scrubber has operated intermittently since then due to mechanical difficulties. During operation, the scrubber has achieved SO_2 removal efficiencies in excess of 90% with no apparent scrubber-related problems. The major problem has been with the design and operation of the $MgSO_3$ crystal dryer. Redesign of the dryer and a change of fuel to a low viscosity oil appear to be resolving these problems. Other problems with centrifuging the sulfite crystals from the scrubbing liquor and properly calcining the sulfite to regenerate MgO appear to be manageable. An availability factor of 85-90% was achieved for June and July of 1973.

This project is quite important because it will be the first time the individual steps of scrubbing, centrifuging, and calcining on an integrated basis for the Chemico process have been combined. Partially funded by EPA, the project involves not only the scrubber, centrifuge, and dryer at the Boston Edison plant but also the calcining and acid plants at Essex Chemical Company in Rumford, Rhode Island.

The first large scale coal-fired application was started up in September of this year at the Dickerson Station of Potomac Electric and Power. Flue gas from approximately 100 MW of the 195 MW of Dickerson Unit 3 will be processed. Since the plant burns coal (3% S, 8% ash), the scrubbing facility uses one venturi scrubber to remove the particulate and a second to remove the SO_2. Regeneration of MgO for this system will be carried out at the Essex Chemical facility which also serves the Boston Edison system.

Process: Cat-Ox
Process Supplier: Monsanto Enviro-Chem Systems, Inc.
Constructor: Leonard Construction Co.
System Location: Illinois Power Company, Wood River Station
East Alton, Illinois

Start-Up Date:

Construction was completed in July 1972 followed by debugging and modification. Acceptance testing was completed July 1973 with full operation to commence April 1974 following provision of additional modifications.

System Description and History of Operation:

The retrofit or "reheat" version of the Cat-Ox System has been installed on the 110 MW coal fired Wood River No. 4 boiler operated by Illinois Power. The process accepts flue gases from the discharge of a specially provided high efficiency ESP. The gases are heated to 850°F by heat exchange with processed gases from the catalytic converter and by supplemental "reheat" burners. The heated gases pass through the fixed bed catalytic converter where SO_2 is oxidized to SO_3. An acid absorbing tower followed by a fiber acid mist eliminator serve to remove the SO_3 prior to discharge of the flue gas to the stack. Product acid is cooled and stored in tankage.

Since its completion in July of 1972, a series of mechanical difficulties have occurred and modifications or repairs have been effected. During July of 1973 an acceptance test was conducted which established the capability of the system to achieve the specified 85% SO_2 removal while producing an acid product of somewhat greater than the required 77.7% concentration. Also, subsequent testing of the high efficiency ESP has established the particulate removal to be sufficient to prevent undue costs for catalyst cleaning. Long term operation of the system has been delayed until April of 1974 due to late delivery of equipment for a planned system modification to permit operation of the reheat burners on fuel oil rather than natural gas.

Process: Limestone scrubbing with throwaway product.
Process Supplier: Combustion Engineering.
Constructor: Combustion Engineering.
System Location: Kansas City Power and Light, Hawthorn Station, Units No. 3 and 4.

In September 1972, the 100 mw Kansas City Power and Light's Hawthorn 3 and 4 started up. Each of the boilers was originally equipped with a boiler injection system and two identical scrubber modules. Unit No. 4 has recently been converted to a tail-end system. Before changing to a tail-end system, boiler pluggage problems were experienced on Unit No. 4. Unit No. 3 still uses boiler injection and has not experienced boiler pluggage. No problems have been reported with the fans or reheaters on either unit. The remaining problems appear to be primarily with the recirculation system. Modifications similar to those used successfully at Combustion Engineering's scrubber at Louisville Gas and Electric Company's Paddy's Run plant show great promise of overcoming these problems. These include problems with headers and drain pots. Demister pluggage has been a problem but this appears to be solved. Some settling has occurred in the recirculation tank but this should be corrected with improvements in the agitation of the tank.

The method of ultimate sludge disposal has not been decided upon. Enough land area is available to enable them to pond the sludge for up to 15 years.

This plant is the last plant installed by Combustion Engineering using the limestone injection technique. Removal efficiencies have been between 70 and 80 percent.

Process: Limestone scrubbing with throwaway product.
Process Supplier: Babcock and Wilcox.
Constructor: Babcock and Wilcox.
System Location: Kansas City Power and Light, LaCygne Station, Unit No. 1.
Startup Date: June 1973.

The SO_2 scrubber at the new 820 mw LaCygne Station started operation in February 1973. The system consists of seven modules. At present, one module is controlling SO_2 and particulate with a venturi scrubber and a grid plate scrubber. The limestone is added to the scrubber rather than to the boiler.

The remaining six modules at LaCygne are controlling particulate only using the venturi section. The grid plate will be installed and limestone added at a future date to control SO_2 for the entire plant.

It is too early to accurately assess the reliability of this system since the boiler is new and has not become fully operational yet. The system is essentially a duplicate of the Will County scrubbing system and has experienced many of the same problems. These include plugging of the demisters, corrosion of the reheater tubes, and other mechanical problems. Like Will County, the problems are mechanical in nature and solvable using state-of-the-art methods. It is worthwhile to note that no chemical problems with the scrubber itself have occurred. It appears likely that the system will achieve reliable operation in the near future.

Unlike Will County, there are no bypass provisions at LaCygne, and no electrostatic precipitators are installed to collect particulate. The scrubbers are expected to achieve 80 percent control of SO_2 as well as satisfactory control of particulate.

One year hold time is available for sludge disposal. Plans beyond that time are uncertain.

Process: Lime Scrubbing with Throwaway Product
Process Supplier: Combustion Engineering
Constructor: Combustion Engineering
System Location: Louisville Gas and Electric Company, Paddy's Run
Station No. 6, Southwest of Louisville
Start-Up Date: April 1973

System Description and History of Operation:

The SO_x control system installed on this 70 MW electric generating unit consists of two parallel, two-stage marble bed scrubbers installed downstream of an electrostatic precipitator. The scrubber effluent liquor enters a large reaction vessel from which some spent liquor is bled to a thickener followed by a rotary drum filter. A carbide sludge slurry which contains lime as the active ingredient is fed to the reaction vessel. This absorbent slurry feed is controlled by a measurement of acidity in the system, and changes as necessary with variations in SO_x throughput. SO_x throughput varies with boiler-generator load and with variation of fuel sulfur content.

Between April and August 1973 the unit has accumulated about 1000 hours of operation. The scrubbers have operated for periods of up to 10-12 days with no problems. SO_x removal has been in the 90% range. There has been no evidence of scaling or plugging. Erosion/corrosion has not been a problem. There have been some minor mechanical problems.

The demisters, two stages of standard chevron, have not been a problem. Demister wash is accomplished once every eight hours with high velocity fresh water at the bottom of the demister. The amount of water used is only that amount needed to make up for normal evaporation and losses with the throwaway sludge. Thus, the system is operated as close to closed loop operation as can be expected.

The limited operation, overall, has not been due to problems for the most part, but due to the lack of operating manpower. During the peak demand periods, when all the Paddy's run units were on line, LG&E has had to shut the scrubber system down since operating manpower was spread thin and operation of the electric generating equipment took first priority.

B. Operational Experience on Japanese Installations

Process: Soluble sodium scrubbing with thermal regeneration (Wellman-Lord).
Process Supplier: Davy Powergas.
Constructor: Mitsubishi Chemical Machinery Company.
System Location: Japan Synthetic Rubber Company (JSR) near Chiba, Japan.
Startup Date: July 1971.

Successful reliable operation of the Wellman-Lord SO_x control process at Chiba with essentially 100 percent availability for over two years is considered quite significant for the U. S. control situation. This process consistently removes over 90 percent of the SO_2 from the exhaust gases of a 75 mw equivalent oil-fired boiler. The load is essentially constant but the concentration of SO_2 varies from 400 to 2000 ppm.

It appears that the process should be applicable to coal-fired boilers if fly ash removal equipment is installed upstream of the absorber. A Northern Indiana Power Service Company (NIPSCO) unit, partially funded by EPA, will evaluate such systems on a coal-fired boiler. Cost studies indicate that capital and operating costs for a Wellman-Lord system in the U. S. on a coal-fired boiler are not a great deal higher than those for wet lime/limestone or magnesium oxide scrubbing systems, which are generally considered the least expensive of the flue gas desulfurization systems. The system is commercially offered and guaranteed in the U. S.

The major problem with the process is the requirement for a bleed to remove contaminants, primarily sodium sulfate (Na_2SO_4). Present information indicates about 10 percent of the total incoming sulfur is lost as soluble Na_2SO_4 at Japan Synthetic Rubber (JSR).

Sodium sulfate is a natural component of sea water but could possibly cause problems in fresh water. This purge has been substantially reduced at the newer installation at Chubu Power and may be further reduced by oxidation retardants research by Sumitomo.

The product of the Wellman-Lord system at JSR is high-purity sulfuric acid. While there may be insufficient markets for the sulfuric acid produced if a large percentage of the plants in the U. S. used this method, there is probably a market available for the output of several plants, particularly those in eastern and midwestern industrial areas.

Elemental sulfur, which will be produced in the NIPSCO unit, is another potential product which is both storable and potentially saleable; this could ultimately be a more desirable end product, especially for utilities not near a market for sulfuric acid. A disadvantage of elemental sulfur production is the necessity of the use of considerable quantities of a reducing agent such as coke or natural gas.

Process: Lime scrubbing with throwaway product.
Process Supplier: Chemical Construction Company (Chemico).
Constructor: Mitsui Miiki Machinery Company.
System Location: Mitsui Aluminum Company, Omuta Power Station, Japan.
Startup Date: March 1972.

The scrubber at Mitsui Aluminum's Omuta Power Station began operation on March 29, 1972. The system uses as an absorbent carbide sludge that is chemically identical to lime with regard to SO_2 scrubbing. The scrubber serves a coal-fired 156 mw boiler that burns coal equivalent to about 2.5 percent sulfur eastern or midwestern U. S. coal. The scrubber has had several load variations similar to, albeit less frequent than, typical U. S. boilers. The system has operated at closed-loop conditions for substantial periods of time and is open loop only occasionally during periods of heavy rain. Fly ash concentration into the scrubber is similar to that for typical U. S. retrofits.

The system has obtained 18 months of continuous, essentially trouble free, operation since startup.

It should be noted that the reliable performance of this system is of real significance to the United States air pollution control program, since the design ground rules for the Japanese unit are quite similar to those of many of our power utilities requiring desulfurization systems. The following are among the areas of commonality: retrofit of existing coal-fired boiler, moderately efficient electrostatic precipitators, installation on moderately-large size boiler, production of a throwaway product, and availability of lime (calcium hydroxide). The unit takes on additional significance since the system was designed based on U. S. technology (Chemico) and is offered and guaranteed in this country. Two similar units using lime on coal boilers are being constructed in the U. S. for Duquesne Light Company's Phillips Station and Ohio Edison's Bruce Mansfield Station.

Process: Sodium Scrubbing with Thermal Regeneration (Wellman-Lord Process)
Process Supplier: Davy Powergas, Inc.
Constructor: Mitsubishi Chemical Machinery (MKK)
System Location: Chubu Electric
Nagoya, Japan
Startup Date: May 1973

System Description and History of Operation:

The Chubu system is applied to a peaking service, oil-fired utility boiler of 220 MW output. The system utilizes a rectangular sieve tray absorber which has maintained SO_2 outlet levels consistently below 150 ppm. Double effect evaporation is utilized for regeneration and a purge crystallization system is provided to minimize sodium loses through purge. The purge crystals have assayed higher than 85% sodium sulfate. The system is designed to treat flue gas from burning of 4% sulfur and to handle changes in boiler load from 25% to 100%. Because of the peaking service application, the system is subjected to frequent weekend shutdowns with no restart problems encountered to date. It is noteworthy that at one point during the recent testing program the boiler fuel was changed from 0.7% sulfur oil to 4% sulfur oil instantaneously through boiler operator error. In spite of this many-fold step change in inlet concentration, outlet concentration of SO_2 remained below 150 ppm.

APPENDIX C - Names and Affiliations of Hearing Witnesses

- Allegheny County (Penna.) Bureau of Air Pollution:
  - FEIGENBAUM, Simon, Engineer
  - GORR, Wilpen L., Dr., Ohio State University

- American Electric Power Service Corporation:
  - CLARKE, A.J., Head, Environmental Studies Group, Central Electric Generating Board, London, England
  - DICKE, Richard M., New York City Law Firm of Simpson, Thacher and Bartlett
  - DOWD, Joseph, Vice President & General Counsel; and Asst Secy of Ohio Power Company
  - FLANNERY, David, Esq.
  - MARTINKA, Paul, Vice President, Fuel Supply
  - REEVES, Robert W., Head of Environmental Engineering Div.
  - SMITH, Maynard, of Smith-Singer Meteorologists of Long Island
  - TILLINGHAST, John, Senior Executive Vice President in charge of Engineering and Construction

- Appalachian Research & Defense Fund:
  - RODECKER, Robert, Esq., Staff Attorney--appearing for Paul Kaufman, former Director

- Arizona Public Service Company:
  - NORTON, Bruce, Esq.
  - WOODS, Thomas G., Jr., Vice President, Engineering

- Babcock and Wilcox:
  - GRIFFIN, E.M., Division Vice President, Power Generation Group
  - STEWART, J.F., Foreman-Supervisor, Air Quality Control Section
- BALET, William, Bureau of Power, Federal Power Commission
- BALZHISER, Richard, Director, Fossil Fuel & Advanced Systems, EEI
- BARNARD, Richard E., Manager, Commercial & Technical Development
- BAUM, Robert, Deputy Asst Administrator for General Enforcement, EPA
- BEARD, Carl G., II, Director, West Virginia Air Pollution Control Commission
- BENZIGER, Peter H., Vice President of Generating, Potomac Electric Power Company
- BETHELL, Thomas N., Research Director, United Mine Workers of Am.
- BLINCKMANN. Robert A., Vice President and General Manager, Air Pollution Control Co., Chemical Construction Corporation
- Boston Edison Company:
  - IRVING, William M., Director, Research & Environmental Affairs
  - QUIGLEY, Christopher P., Director, Mechanical & Structural Design Division
- BOYER, Vincent S., Vice President in Charge of Engineering, Philadelphia Electric Company
- BRADSTREET, Jeffrey, Dr., NUS Corp., Appearing for NIPSCO
- BRECHER, Joseph T., Esq., Native American Rights Fund

- Buckeye Power Company:
  - MONE, Robert, General Counsel
- BURCHARD, John, Director, Control Systems Laboratory, EPA
- CARSON, J.H., General Production Environmental & Performance Engineer, Ohio Edison Company

Combustion Equipment Associates, Inc. (CEA):
SHAH, I.S.

Chemfix Division of Environmental Sciences, Inc.:
CONNER, Jesse, President

Chemical Construction Corporation:
BLINCKMANN, Robert A., Vice President & General Manager of CCC's Air Pollution Control Company
QUIG, Robert H., Vice President, Business Development
WECHSELBLATT, Peter, Manager, Process Engineering

Citizen's Environmental Task Force:
MADOFF, Michelle
CLARKE, A.J., Head, Environmental Studies Group, CEGB, appearing for American Electric Power
CLAYTON, Cubia, Chief, Air Quality Div., New Mexico Environmental Improvement Agency

Combustion Engineering, Inc.:
JONAKIN, Jim, Project Manager, Air Quality Control Systems
SINGER, Joe, Director, Special Projects Engineer

Commonwealth Edison Company:
LEE, Byron, Jr., Vice President
MARCUS, George, Director of Fuels
POWELL, Richard, Esq., Cross-examining Frank Princiotta
SMYK, Eugene, Chemical Engineer, Will County Station
CONNER, Jesse, President, Chemfix Div., Environmental Sciences, Inc.
CRAIG, John M., Dr., Senior Research Engineer, Southern Services, appearing for Edison Electric Institute
CRAMER, John, Esq., Duquesne Light Co.
CRAWFORD, W. Donham, President, Edison Electric Institute

Davy Powergas:
EARL, Christopher, Director, Process Section
WATT, Stewart, Senior Vice President

Detroit Edison Co. and Peabody Engineered Systems: (Joint Statement)
SALEEM, Ab, Dr., of Peabody
WILLETT, H.B., of Peabody
DICKE, Richard M., Esq., NYC Law Firm of Simpson, Thacher and Bartlett, appearing for American Electric Power
DOWD, Joseph, Vice President and General Counsel, American Electric Power and Asst. Secretary of Ohio Power Company
DUNKELBERGER, Ed, Esq., of Covington & Burling, appearing on behalf of Public Service Co. of Indiana

Duquesne Light Company:
CRAMER, John, Esq., Attorney
PERNICK, Steve L., Jr., Manager, Environmental Affairs
EARL, Christopher, Director, Process Section, Davy Powergas
EBERHART, Russell, Dr., Maryland Power Plant Siting Program

- Edison Electric Institute:
  - BALZHISER, Richard, Director of Fossil Fuel & Advanced Systems
  - CRAWFORD, W. Donham, President
  - CRAIG, John M., Dr., Senior Research Engineer, Southern Services, Inc., appearing on behalf of Edison Electric Inst.
  - GIFFORD, Donald C., General Engineer, Commonwealth Edison Co.
  - SMITH, Maynard E., President, Smith-Singer Meteorologists, Inc.
- EICHHORN, Fred F., Esq., appearing for Northern Indiana Public Service Company
- ELDER, William, Director, Stack Gas Emission Studies Staff, TVA
- ENGDAHL, Richard B., Atmospheric Chemistry & Combustion Research Section, Battelle-Columbus Laboratories, appearing for West Penn Power Co.

- Environmental Protection Agency:
  - BAUM, Robert, Deputy Asst Administrator for General Enforcement
  - BURCHARD, John, Director, Control Systems Laboratory
  - LUNEBURG, William, Esq., Enforcement Division, Region V
  - McDONALD, James O., Director, Enforcement Division, Region V
  - PADGETT, Joseph, Project Standards Division
  - PRINCIOTTA, Frank T., Chief, Non-Regenerable Section:
  - QUARLES, John R., Deputy Administrator
  - RASNIC, John, Chief, Air Compliance Branch, Region III
  - SANSOM, Robert L., Asst Administrator, Air & Water Programs
  - SHEPARD, John, Chief, Legal Branch, Enforcement Div., Region III
  - STEIGERWALD, Bernard J., Dr., Director, Office of Air Quality Planning and Standards
  - TRAIN, Russell E., Administrator
  - TRAINA, Paul J., Director, Enforcement Division, Region IV
  - WILBURN, James T., Chief, Air Enforcement Division, Region IV
  - WILSON, Richard D., Director, Division of Stationary Source Enforcement
- ERDMAN, Mr., Project Engineer, Potomac Electric Power Company
- FARKAS, Alan L., Deputy Director for Policy Development, Ohio EPA

- Federal Power Commission:
  - BALET, William, Bureau of Power
  - JIMESON, Robert M., Office of Advisor on Environmental Quality
  - JOURNEY. Drexel, Deputy General Counsel
- FEIGENBAUM, Simon, Engineer, Allegheny County (Penna.) - Bureau of Air Pollution
- FEIN, Marvin, Director, Bureau of Litigation Enforcement - Penna. Dept. of Environmental Resources
- FLANNERY, David, Atty, Representing American Electric Power
- GARRETT, Theodore, Esq. of Covington & Burling, appearing for Public Service Co. of Indiana--cross-examining F. Princiotta
- GARTRELL, Frank, Director, Environmental Planning, TVA
- GAULDING, Clark L., Director, Bureau of Air Quality and Noise Control, Penna. Dept. of Environmental Resources
- GEIST, Jerry, Executive Vice President, Public Service Company of New Mexico

GERSTLE, Richard W., PEDCO Environmental:
  Reporting on a study of Mitchell Station, West Penn Power Co.
  Reporting on a study of Bailly Station, NIPSCO
  Reporting on a study of Wabash River Station, PSI
GIFFORD, Donald C., General Engineer, Commonwealth Edison Co., appearing on behalf of Edison Electric Institute
GORR, Wilpen L., Dr., Ohio State University
GREEN, George, Director of Engineering, Environmental Engineering and Planning, Public Service Company of Colorado
GRIFFIN, E.M., Division Vice President, Power Generation Group, Babcock Wilcox
HARRIS, Thomas O., Commissioner, Kentucky Dept. of Natural Resources and Environmental Protection
HARRISON, Douglas, Engineer, Hydroelectric Power Commission of Ontario, appearing for West Penn Power Company
HESKETH, Howard E., Professional Engineer

Illinois Power Company:
  MILLER, Wendell, Director of Environmental Affairs
  SHULTZ, Emerson A., Senior Vice President

Indiana Air Pollution Control Board:
  WILLIAMS, Harry D., Director, Division of Air Pollution Control

Industrial Gas Cleaning Institute:
  OREM, Sidney R., Technical Director
IRVING, William M., Director, Research & Environmental Affairs, Boston Edison Company

I. U. Conversion Systems, Inc:
  MINNICK, L, John, Executive Vice President
IVES, Joseph S., Environmental Counsel, NRECA

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  OFFUTT, Robert T., Secretary-Treasurer
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Kansas City Power and Light Company:
  McPHEE, Donald T., Vice President, Production
KAUFMAN, Paul, former Director, Appalachian Research and Defense Fund

KEBSCHULL, William David, Bureau of Air Quality, Maryland Department of Health and Mental Hygiene

Kennecott Copper Corporation:
  SWAN, David, Vice President--Technology
KENNEDY, James M.. Jr., Chairman, Tennessee Valley Industrial Com.

Kentucky, State of:
  HARRIS, Thomas O., Commissioner, Dept. for Natural Resources and Environmental Protection

KIMBERLIN, Greg, Esq., Atty for Public Service Company of Indiana
KOLFLAT, Tor, of Sargent & Lundy--Engineers, appearing for Public Service Company of Indiana
KUHLMAN, George C. of Sargent & Lundy--Engineers, appearing for Northern Indiana Public Service Company
LEE, Byron, Jr., Vice President, Commonwealth Edison Co.

Louisville Gas & Electric Company:
MAYROSE, J.F., Executive Vice President
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McVAY, Cecil, Operating Vice President, Allegheny Power Services, appearing for West Penn Power Company
MADOFF, Michelle, Citizens Environmental Task Force
MANSFIELD, Bruce, President, Ohio Edison Co. & Chairman of the Board of Pennsylvania Power Company
MARCUS, George, Director of Fuels, Commonwealth Edison Co.
MARTINKA, Paul, Vice President, Fuel Supply, American Electric

Maryland, State Bureau of Air Quality Control:
EBERHART, Russell, Dr., Md. Power Plant Siting Program
KEBSCHULL, William David
MATTHEWS, Walter J., President, Public Service Co. of Indiana
MAYROSE, J.F., Executive Vice President, Louisville Gas & Elec.
MILLER, Wendell, Director of Environmental Affairs, Illinois Power Co.
MINNICK, L. John, Executive Vice President, I.U. Conversion Systems, Inc.
MLECZKO, Stanley S., Vice President and General Manager, UOP
MONE, Robert, General Counsel, Buckeye Power Co.

Monsanto Enviro-Chem Systems:
BARNARD, Richard E., Manager, Commercial & Technical Development
MOORE, Jack B., Vice President, Southern California Edison

National Rural Electric Cooperative Association:
IVES, Joseph S., Environmental Counsel

Native American Rights Fund:
BRECHER, Joseph T., Atty

New Mexico Environmental Improvement Agency:
CLAYTON, Cubia, Chief, Air Quality Division

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KUHLMAN, George, of Sargent & Lundy--Engineering Firm
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Ohio Edison Company:
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- SALEEM, Ab, Dr., of Peabody Engineered Systems
- WILLETT, H.B., Mr., of Peabody Engineered Systems

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Pennsylvania Department of Environmental Resources:
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- GAULDING, Clark L., Director, Bureau of Air Quality & Noise Con.

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- BOYER, Vincent S., Vice President in Charge of Engineering

PIERCE, Donald, Economist, United Mine Workers of America

POHLENZ, J. B., Dr., Process Division, UOP

Potomac Electric Power Company:
- BENZIGER, Peter H., Vice President of Generating
- ERDMAN, Mr., Project Engineer

POWELL, Richard, Esq., Representing Commonwealth Edison Co., Cross-examining F. Princiotta

PRINCIOTTA, Frank T., Chief, Non-Regenerable Process Section, EPA

Public Service Company of Colorado:
- GREEN, George, Director of Engineering, Environmental Engineering and Planning
- WALKER, Richard F., Vice President of Engineering and Planning, Electric Department

Public Service Company of Indiana:
- DUNKELBERGER, Ed, Esq., of Covington & Burling
- GARRETT, Theodore, Esq., of Covington & Burling - Cross-examining F. Princiotta
- KIMBERLIN, Greg, Attorney

KOLFLAT, Tor, of Sargent and Lundy--Engineers
MATTHEWS, Walter J., President
SHIELDS, S. W., Chief Engineer

Public Service Company of New Mexico:
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SLAMINSKI, Mike, Supervisor, Resource and Process Analysis
QUARLES, John R., Deputy Administrator, EPA
QUIGLEY, Christopher P., Director, Mechanical & Structural Design Division, Boston Edison Co. - Mr. Quigley's remarks were interspersed with Mr. Irving's statement
QUIG, Robert H., Vice President, Business Development, Chemico
RASNIC, John, Chief, Air Compliance Branch, EPA, Region III
REEVES, Robert W., Head of Environmental Engineering Div., AEP

Research-Cottrell, Inc.:
STITES, Joseph, Jr., Director, Program Management
RODECKER, Robert, Staff Attorney, Appalachian Research and Defense Fund - Appearing for Paul Kaufman, former Director of ARDF
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SHIELDS, S.W., Chief Engineer, Public Service Co. of Indiana

Sierra Club:
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Appearing on behalf of American Electric Power
SMYK, Eugene, Chemical Engineer, Will County Station, Commonwealth Edison Co.

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GARTRELL, Frank, Dr., Director, Environmental Planning
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Tennessee Valley Industrial Cooperative (TVIC):
KENNEDY, James M., Chairman
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TSCHAPPAT, D.W., Chief Industrial and Mechanical Engineer, Ohio Edison Co.
TRAIN, Russell E., Administrator, EPA
TRAINA, Paul J., Director, Enforcement Division, Region IV, EPA

United Mine Workers of America:
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PIERCE, Donald, Economist

Universal Oil Products Company:
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WATT, Stewart, Senior Vice President, Davy Powergas
WESCHSELBLATT, Peter, Manager, Process Engineering, Chemico Corp.

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ENGDAHL, Richard B., Atmospheric Chemistry & Combustion, Research Section, Battelle-Columbus Laboratories
HARRISON, Douglas, Engineer, Hydroelectric Power Commission of Ontario
McVAY, Cecil, Operating Vice President, Allegheny Power Services
PENKALA, Stanley J., Dr., Chief, Air Pollution Engineer, DeNardo & McFarland Weather Services, Inc.
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WILLETT, H.B., Peabody Engineered Systems
WILLIAMS, Harry D., Director, Division of Air Pollution Control, State of Indiana
WILSON, Richard D., Director, Division of Stationary Source Enforcement, EPA
WOODS, Thomas G., Jr., Vice President, Engineering, Arizona Public Service Company